BLUE DOLPHIN ENERGY CO
Form 10KSB
March 28, 2002

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-KSB

X Annual Repor t Pursuant to Section 13 or 15(d) of the Securities Act of 1934

For the fiscal year ended December 31, 2001

or

Transition eport Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the transition period from ____________ to ____________

Commission file Number: 0-15905

BLUE DOLPHIN ENERGY COMPANY
(Name of small business issuer in its charter)

Delaware	73-1268729
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
801 Travis, Suite 2100, Houston, Texas	77002
(Address of principal executive office)	(Zip Code)

Issuer's telephone number (713) 227-7660

Securities registered pursuant to Section 12(b) of the Exchange Act: None

Securities registered pursuant to Section 12(g) of the Exchange Act:
common stock, $.01 par value
(Title of Class)

Check whether the issuer (1) filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the past 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes X No

Check if there is no disclosure of delinquent filers in response to Item 405 of Regulation S-B contained in this form, and no disclosure will be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-KSB or any amendment to this Form 10-KSB. X

The issuer's revenues for the year ended December 31, 2001 were $5,686,025.

The aggregate market value of the voting stock held by non-affiliates of the registrant as of March 22, 2002, was approximately $6,624,578.

As of March, 22, 2002, there were outstanding or in the process of distribution 6,371,845 shares of common stock, par value $.01 per share, of the issuer.

Documents Incorporated By Reference

The registrant's definitive proxy statement for the 2002 Annual Meeting of Stockholders of the registrant (Sections entitled "Ownership of Securities of the Company", "Election of Directors", "Executive Compensation" and "Transactions With Related Persons"), to be filed with the Securities and Exchange Commission pursuant to Regulation 14A, is incorporated by reference in Part III of this report.

PART I

Item 1. Business

Forward Looking Statements. Certain of the statements included in this annual report on Form 10-KSB, including those regarding future financial performance or results or that are not historical facts, are "forward-looking" statements as that term is defined in the Section 21E of the Securities Exchange Act of 1934, as amended, and Section 27A of the Securities Act of 1933, as amended. The words "expect", "plan", "believe", "anticipate", "project", "estimate", and similar expressions are intended to identify forward-looking statements. Blue Dolphin Energy Company (referred to herein, with its predecessors and subsidiaries, as "Blue Dolphin" or the "Company") cautions readers that any such statements are not guarantees of future performance or events and such statements involve risks and uncertainties that may cause actual results and outcomes to differ materially from those indicated in forward-looking statements. Some of the important factors, risks and uncertainties that could cause actual results to vary from forward-looking statements include:

- the risks associated with exploration;
- gas and oil price volatility;
- uncertainties in the estimation of proved reserves and in the projection of future rates of production and timing of development expenditures;
- availability and cost of capital;
- actions or inactions of third party operators for properties where the Company has an interest;
- regulatory developments; and
- general economic conditions.

Additional factors that could cause actual results to differ materially from those indicated in the forward-looking statements are discussed under the caption "Risk Factors". Readers are cautioned not to place undue reliance on these forward-looking statements which speak only as of the date hereof. The Company undertakes no duty to update these forward-looking statements. Readers are urged to carefully review and consider the various disclosures made by the Company which attempt to advise interested parties of the additional factors which may affect the Company's business, including the disclosures made under the caption "Management's Discussion and Analysis of Financial Condition and Results of Operations" in this report.

THE COMPANY

The Company conducts its business activities in two primary business segments: (i) oil and gas exploration and production, which includes our developmental-stage upstream projects, and (ii) pipeline operations, which includes our developmental-stage mid-stream projects. The Company's oil and gas exploration and production activities include the exploration, acquisition, development, operation and, when appropriate, disposition of oil and gas properties. The Company focuses its oil and gas acquisitions and exploration activities in the western and central Gulf of Mexico.

The Company is a holding company that conducts substantially all of its operations through its subsidiaries. Substantially all of the Company's assets consist of equity in its subsidiaries. The Company's subsidiaries and affiliates are as follows:

- American Resources Offshore, Inc., a Delaware corporation;
- Blue Dolphin Petroleum Company, a Delaware corporation;
- Blue Dolphin Exploration Company, a Delaware corporation;
- Blue Dolphin Pipe Line Company, a Delaware corporation;
- Blue Dolphin Services Co., a Texas corporation;
- Petroport, Inc., a Delaware corporation;
- New Avoca Gas Storage, LLC, a Texas limited liability company in which the Company owns a 25% interest; and
- Drillmar, Inc., a Delaware corporation in which the Company owns a 12.8% interest.

Effective January 1, 2002, two wholly owned subsidiaries, Mission Energy, Inc. and Buccaneer Pipe Line Co. were merged into Blue Dolphin Pipe Line Company.

The principal executive office of the Company is located at 801 Travis, Suite 2100, Houston, Texas, 77002, telephone number (713) 227-7660. Shore based facilities are maintained in Freeport, Texas serving Gulf of Mexico operations. The Company has 15 full-time employees. The Company's common stock is traded on the National Association of Securities Dealers, Inc. Automated Quotation System ("NASDAQ") Small Cap Market under the trading symbol "BDCO". The Company's home page address on the world wide web is http://www.blue-dolphin.com.

Recent Developments

On December 2, 1999, the Company, through Blue Dolphin Exploration, acquired a 75% ownership interest in American Resources by purchasing approximately 39.5 million shares of American Resources Common Stock. On February 19, 2002, the Company completed its acquisition of American Resources, pursuant to the Amended and Restated Agreement and Plan of Merger dated as of December 19, 2001 (the "Merger Agreement"). Pursuant to the Merger Agreement, American Resources became a wholly owned subsidiary of the Company and each outstanding share of (i) American Resources common stock, par value $.00001 per share, was converted into the right to receive, at the option of the holder, either $.06 per share in cash or .0362 of a share of the Company's common stock, par value $.01 per share (the "Common Stock"), and (ii) American Resources Series 1993 Preferred Stock, par value $12.00 per share, was converted into the right to receive, at the option of the holder, either $.07 in cash or .0301 of a share of Common Stock.

As a result of elections made by American Resources' stockholders, the Company will issue approximately 273,336 shares of Common Stock and will pay approximately $255,000 in cash.

In February 2002, the Company acquired a 1/3 interest in the Blue Dolphin Pipeline System and the inactive Omega Pipeline from MCNIC Pipeline and Processing Company ("MCNIC"). Pursuant to the terms of the purchase and sales agreement, Blue Dolphin issued MCNIC a $750,000 promissory note due December 31, 2006, with required monthly payments to be made out of 90% of the net revenues of the interest acquired. The note bears interest at the rate of 6% per annum and is secured by the interest acquired. Additionally, contingent payments of up to $750,000 will be made, if the promissory note is retired before its maturity date, payable annually after the promissory note is retired until December 31,

2006, out of 50% of the net revenues from the interest acquired. The termination date, December 31, 2006, will be extended by one additional year, up to a maximum of two years, for years in which non-recurring, extraordinary expenditures attributable to the interest acquired, exceeds $200,000, in the aggregate, during any year.

Oil and Gas Exploration and Production Activities

The Company's oil and gas assets are held, and operations conducted, by American Resources, Blue Dolphin Petroleum and Blue Dolphin Exploration. The Company's oil and gas assets consist of leasehold interests in properties located offshore in the Gulf of Mexico. The leasehold properties held by the Company are subject to royalty, overriding royalty and interests of others. In the future, the Company's properties may become subject to burdens and encumbrances typical to oil and gas operators, such as liens incident to operating agreements and current taxes, development obligations under oil and gas leases and other encumbrances.

Certain terms that are commonly used in the oil and gas industry, including terms that define the Company's rights and obligations with respect to each of its properties, are defined in the "Glossary of Certain Oil and Gas Terms" on pages 27, 28 and 29 of this Form 10-KSB.

The following is a description of the Company's major oil and gas exploration and production assets and activities:

The Buccaneer Field. The Company owned a 100% working interest in the Buccaneer Field (81.33% net revenue interest). Production from the Buccaneer Field accounted for 5% of the total revenues from oil and gas sales of the Company for the year ended December 31, 2000. In addition to conducting traditional oil and gas production operations for itself, the Company operated and maintained oil and gas production facilities for third party producers who utilized the Blue Dolphin Pipeline System for gathering and transportation of their production. The Company had a contract to provide operation and maintenance services to another company, which during 2000, accounted for approximately 3% of the Company's revenues.

In November 2000, after considering the costs associated with drilling a new well to reestablish production, together with the unplanned cost of repairs to the platforms, approximately $5.8 million, and the projected rate of production and discounted cash flow from the field the Company decided to abandon and not reestablish production from the Buccaneer Field. As a result of this decision, the leases in this field terminated in January 2001 pursuant to their terms, and the Company's operation and maintenance services contract was terminated in December 2000.

As a result of the termination of the Company's leases in or around the Buccaneer Field, the Company must plug and abandon all remaining wells and remove platform facilities. The U.S. Minerals Management Service ("MMS") requires that security be provided for the estimated abandonment obligations associated with the Buccaneer Field. Blue Dolphin Exploration provided the MMS surety bonds in the amount of $4.2 million. The rules and regulations of the MMS require that the Company complete the plugging and abandonment within one year after termination of the lease. In the first quarter of 2001, the Company plugged and abandoned the remaining wells at a cost of approximately $1.4 million. Work to remove the two platform facilities began in August 2001 with costs of $443,000 incurred as of December 31, 2001. The Company used all of its escrowed funds of approximately $1.5 million to pay for plugging and abandonment operations in 2001.

During the removal of the platform complexes in October 2001, the Company initiated discussions with the Texas Parks and Wildlife ("TP&W") in an effort to leave certain under water portions of the platform complexes in place

as artificial reefs. In December 2001, operations to remove the platform complexes were suspended while the Company continues its discussions with the TP&W. The Company expects that the TP&W will make a decision to leave either one, two or neither of the Buccaneer Field platform complexes in place as artificial reefs in the second quarter 2002. If the TP&W allows the Company to leave one or both of the platform complexes as an artificial reef, certain site clearance costs would be eliminated. The Company requested and has received an extension from the MMS until October 1, 2002 to complete the removal and site clearance of the platform complexes. The Company believes that its provision for abandonment costs of $4.6 million at December 31, 2001 is adequate.

Until abandonment operations were suspended in December 2001, significant progress was made. Both platform complexes include a production platform with a bridge connected quarters platform. At the complex located in GA Block 288, the decks on both the production and quarters platforms and the bridge have been removed. At the complex located in GA Block 296, the deck on the quarters platform, a portion of the deck on the production platform and the bridge have been removed. If the TP&W does not allow the Company to leave either of the platform complexes in place, the Company will have to remove the remaining portion of the GA Block 296 production platform deck and the under water platform structures and conduct site clearance.

American Resources. The oil and gas properties held by American Resources represent more than 99% of the discounted present value of estimated future net revenues from proved reserves of the Company as of December 31, 2001. Sales of production from the these properties accounted for 100% of oil and gas sales revenues and 83% of total revenues of the Company for the year ended December 31, 2001.

The following table provides information regarding the Company's proved reserves, all of which are held through American Resources, as of December 31, 2001:

Proved Reserves
From American Resources Offshore, Inc.

	Oil (Bbl)	Gas (MMcf)	Gas Equivalent (Mmcfe)
South Timbalier 148	33,543	1,153	1,354
Ship Shoal 150	91,022	169	715
West Cameron 172	1,710	546	556
South Timbalier 211	2,262	399	413
West Cameron 368	2,129	342	365
Other	169	355	356
Total net proved reserves	130,835	2,964	3,749

Significant Fields. As of December 31, 2001, all of American Resources oil and gas properties were located on the outer continental shelf of the Gulf of Mexico and consisted of interests in 17 leases. American Resources' working interest in these leases ranges from 10% to 1%, with an average working interest of approximately 5.5%. Of these leases, 10 are offshore Louisiana and 7 are offshore Texas. Eleven of the leases are currently producing, and 6 are held for future development. Those leases that are not producing are in their primary term. The expiration of the primary terms of the undeveloped leases occurs as follows: 5 in 2002 and 1 in 2003.

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South Timbalier 148. South Timbalier Block 148 is located 30 miles offshore Louisiana in an average water depth of 100 feet and is operated by Newfield Exploration Company. American Resources owns a working interest in the lease on the west half of the block that covers approximately 2,500 acres and working interests in seven producing wells on three production platforms. American Resources' working interest in the wells ranges from 9% to 1%.

Ship Shoal 150. Ship Shoal Block 150 is located 31 miles offshore Louisiana in an average water depth of 53 feet. American Resources owns a 10% working interest in 4,297 acres in the block, and working interests in two producing wells on the lease operated by Century Exploration Company ("Century"). American Resources also owns an overriding royalty interest in one producing well on the lease.

West Cameron 172. West Cameron Block 172 is located 25 miles offshore Louisiana in an average water depth of 40 feet. American Resources owns a 5.4% working interest that covers approximately 5,000 acres and working interests in four producing wells on this lease, which are operated by Pure Resources, Inc. ("Pure").

South Timbalier 211. South Timbalier Block 211 is located 42 miles offshore Louisiana in an average water depth of 140 feet. American Resources owns a 6.0% working interest in this lease that covers approximately 5,000 acres and working interests in two producing wells on the lease, which are operated by The William G. Helis Company. American Resources owns an overriding royalty interest in one well on the lease that was drilled under a farmout by Spinnaker Exploration Company, L.L.C. ("Spinnaker"), during 1999 and commenced production in the first quarter of 2000.

West Cameron 368. West Cameron Block 368 is located 63 miles offshore Louisiana in an average depth of 69 feet and is operated by Century. American Resources owns a 6% working interest in 5,000 acres and four producing wells.

Other. Other leases that contain proved reserves are High Island Block 37, offshore Texas, accounting for 33 Mmcfe; and Galveston Block 418, offshore Texas, accounting for 323 Mmcfe.

Offshore Oil and Gas Prospect Generation Activities. The Company has developed oil and gas exploration prospects in the Gulf of Mexico for sale to third parties. The Company has seismic and other data to evaluate and develop prospects. The Company owns a non-exclusive license to 200 blocks of 3-D seismic data covering 1,152,000 acres in the western Gulf of Mexico and a substantial inventory of close grid 2-D seismic data. In addition to recovering prospect development costs, the Company seeks to retain a reversionary working interest in each drillable prospect it sells.

In 1999, the Company had an agreement with Fidelity Oil, whereby in exchange for certain participation rights in prospects generated by the Company, Fidelity Oil paid $100,000 per month of the Company's costs associated with the prospect generation program. Program costs were reimbursed to the Company as prospects were developed and leases acquired. When leases were acquired, a portion of the costs that were previously paid by Fidelity Oil were reimbursed to it based on the level of interest Fidelity retained in each prospect. In April 2000, the Company amended the agreement with Fidelity Oil whereby in exchange for the right to acquire up to 100% of the working interest in prospects generated by the Company, Fidelity Oil paid, on a monthly basis, the costs associated with the program, which totaled $1.1 million during 2000. Fidelity Oil also reimbursed the Company for the cost of additional seismic data acquired. The available interests in the prospect inventory are held for sale on an individual prospect basis.

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Effective December 31, 2000, Fidelity Oil withdrew from the program and the Company suspended the program.

As a result of Fidelity Oil's withdrawal, in January 2001, the Company entered into a consulting agreement with Cheyenne Petroleum Co., whereby the Company's remaining prospect generation staff provided technical consulting services to Cheyenne in the evaluation of prospects for the March 2001 central Gulf of Mexico federal lease sale. In exchange, Cheyenne reimbursed the Company for personnel costs and allowed the Company to participate in prospects generated with a 5% working interest in four undeveloped offshore blocks. This agreement terminated April 30, 2001.

The Company's leased prospect inventory, which it continues to market, consists of prospects on the following offshore leases:

o Mustang Island Area Block 817
o Mustang Island Area Block 839

The Company has reversionary working interests in several offshore leases. Generally, the Company is entitled to its reversionary interest when the other working interest owners receive a return of their investment in operations calculated on a lease wide basis, rather than a well-by-well basis. These leases are:

o High Island Area Block A-7

o Galveston Area Block 297
o Matagorda Island Area Block 713
o Galveston Area Block 271
o Galveston Area Block 284
o Galveston Area Block 285
o Matagorda Island Area Block 710

High Island Block A-7. A gas discovery was made in High Island Area Block A-7, in the Gulf of Mexico, in April 2000. The Company owns an 8.9% reversionary working interest in this field that is operated by Spinnaker. The Company will begin to receive revenues from its reversionary interest after "payout" occurs. Payout will occur after all of the working interest owners have recovered their costs and expenses associated with developing the field from sales of production from the field. At December 31, 2001, there was one well producing in this field at a rate of approximately 23 Mmcf of natural gas per day. During 2001, production from two producing wells ceased with no plans for these wells to be reworked, and two unsuccessful exploratory wells were drilled. Currently, there is one well producing from this field at a rate of approximately 14 Mmcf of natural gas per day. As a result of these occurrences, the Company now expects to begin to receive revenues from its reversionary working interest in this field in 2005.

Other. In connection with Blue Dolphin Exploration's acquisition of a controlling interest in American Resources in December 1999, Blue Dolphin Exploration arranged for Fidelity Oil to acquire an 80% interest in American Resources oil and gas assets located in the Gulf of Mexico for approximately $24.2 million. For the right to participate in the acquisition of these assets, Fidelity Oil agreed to assign Blue Dolphin Exploration 10% of its working interest in the proved properties of American Resources after it recovered its investment in these properties. In addition, Fidelity Oil agreed to assign Blue Dolphin Exploration 15% of its working interest in each exploratory property after Fidelity has recovered its investment in these exploratory properties on a property by property basis.

In the fourth quarter 2001, Fidelity Oil recovered its investment in the proved properties. However, instead of assigning 10% of its interest in the proved properties, Fidelity paid Blue Dolphin $1.4 million in December 2001, for the property interest owed to Blue Dolphin.

Proved Oil and Gas Reserves. Estimates of proved reserves, future net revenues, and discounted present value of future net revenues to the net interest of the Company have been prepared as of December 31, 2001, by Ryder Scott Company, an independent petroleum engineering consulting firm. Proved gas reserves were 79% of total proved reserves at December 31, 2001.

The following table presents the estimates of Proved Reserves, Proved Developed Reserves, and Proved Undeveloped Reserves (as hereinafter defined), future net revenues and the discounted present value of future net revenues from Proved Reserves before income taxes to the net interest of the Company in oil and gas properties as of December 31, 2001. The discounted present value of future net revenues and future net revenues are calculated using the SEC Method (defined below) and are not intended to represent the current market value of the oil and gas reserves the Company owns.

PROVED RESERVES
As of December 31, 2001

	Net Oil Reserves (Mbbls)	Net Gas Reserves (Mmcf)	Future Net Revenues (in thousands)	Pre
Total Proved:				
American Resources (2)	130.8	2,964	$ 7,395	
High Island A-7	0.1	46	28	
Total Proved Reserves	130.9	3,010	$ 7,423	
Total Proved Developed Reserves:				
American Resources (2)	128.7	2,613	$ 6,810	
High Island A-7	0	0	(13)	
Total Proved Developed Reserves	128.7	2,613	$ 6,797	
Total Proved Undeveloped Reserves:				
American Resources (2)	2.1	351	$ 585	
High Island A-7	0.1	46	41	
Total Proved Undeveloped Reserves	2.2	397	$ 626	

(1) The estimated discounted present value of future net revenues before deductions for income taxes from the Company's Proved Reserves have been determined by using prices of $17.70 per barrel of oil and $2.78 per Mcf of gas, representing the December 31, 2001 prices for oil and gas and discounted at a 10% annual rate in accordance with requirements for reporting oil and gas reserves pursuant to regulations promulgated by the United States Securities and Exchange Commission (the "SEC Method").

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(2) As of December 31, 2001 the Company's ownership in American Resources was 77%. The above reflects 100% of American Resources' reserves and future net revenues. 23% of estimated discounted present value of future net revenues associated with total proved reserves, total proved developed reserves and total proved undeveloped reserves of American Resources' properties is $1,380,931, $1,266,641 and $114,290, respectively. Effective February 19, 2002, American Resources became a wholly-owned subsidiary of the Company.

The quantities of proved gas and oil reserves presented include only those amounts which the Company reasonably expects to recover in the future from known oil and gas reservoirs under existing economic and operating conditions. Therefore, proved reserves are limited to those quantities that are believed to be recoverable at prices and costs, and under regulatory practices and technology existing at the time of the estimate. Accordingly, changes in oil and gas prices, operation and development costs, regulations, technology, future production and other factors, many of which are beyond the Company's control, could significantly affect the estimates of proved reserves and the discounted present value of future net revenues attributable thereto.

Estimates of production and future net revenues cannot be expected to represent accurately the actual production or revenues that may be recognized with respect to oil and gas properties or the actual present market value of such properties. For further information concerning the Company's Proved Reserves, changes in Proved Reserves, estimated future net revenues and costs incurred in the Company's oil and gas activities and the discounted present value of estimated future net revenues from the Company's Proved Reserves, see Note 12 - Supplemental Oil and Gas Information to Consolidated Financial Statements included in Item 7.

Capital Expenditures for Proved Reserves. The following table presents information regarding the costs the Company expects to incur in development activities associated with its proved reserves. These expenditures include recompletion costs, workover costs and the cost of drilling additional wells required to recover proved reserves. The information regarding proved reserves summarized in the preceding table assumes the following estimated capital expenditures in the years indicated.

Estimated Capital Expenditures For Proved Reserves
For the years ending December 31,
(in thousands)

	2002	2003	2004	2005	2006
American Resources	$ 150	$ 328	$ 81	$ 104	$ 212
High Island Block A-7	0	0	0	7	13
Total	$ 150	$ 328	$ 81	$ 111	$ 225

Management will continue to evaluate its capital expenditure program based on, among other things, demand and prices obtainable for the Company's production. The availability of capital resources and the willingness of other working interest owners to participate in development operations may affect the Company's timing for further development, and there can be no assurance that the timing of the development of such reserves will be as currently planned.

Productive Wells and Acreage. The following table sets forth the number of productive oil and gas wells in which the Company owned an interest and the developed and undeveloped acreage as of December 31, 2001. "Gross" as it applies to wells or acreage refers to the number of wells or acres in which a working interest is owned, while "net" applies to the sum of the fractional working interests in gross wells or acreage.

ACREAGE AND WELLS

	Productive Wells (1)				Acres			
	Gross		Net		Developed (2)		Undeveloped (3)	
	Oil	Gas	Oil	Gas	Gross	Net	Gross	Net
American Resources (4)	5	18	0.30	0.83	32,848	1,754	42,275	2,364

(1) "Productive wells" are producing wells and wells capable of production, and include gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities. Wells that are completed in more than one producing horizon are counted as one well.

(2) "Developed acres" include all acreage as to which proved reserves are attributed, whether or not currently producing, but exclude all producing acreage as to which the Company's interest is limited to royalty, overriding royalty, and other similar interests.

(3) "Undeveloped acres" are considered to be those acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and gas regardless of whether such acreage contains Proved Reserves.

(4) As of December 31, 2001 the Company's ownership interest in American Resources was 77%. The above reflects 100% of American Resources' acreage and wells.

Production, Price and Cost Data. The following table presents information regarding production volumes and revenues, average sales prices and costs (after deduction of royalties and interests of others) with respect to crude oil, condensate, and gas attributable to the interest of the Company for each of the periods indicated.

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NET PRODUCTION, PRICE AND COST DATA

	Year Ended December 31,		
	2001	2000	1999
Gas:			
Production (Mcf)	815,184	911,671	169,329
Revenue	$3,607,910	$3,674,192	$393,125
Average Production (Mcf) per day	2,233.4	2 ,490.9	463.9
Average Sales Price			
Per Mcf	$ 4.43	$ 4.03	$ 2.32

Oil:			
Production (Bbls)	40,769	64,707	6,338
Revenue	$1,086,292	$1,844,948	$151,974
Average Production (Bbls) per day	111.7	176.8	17.4
Average Sales Price Per Bbl	$ 26.65	$ 28.51	$ 23.98
Production Costs (1):			
Per Mcfe:	$ 1.06	$ 1.05	$ 4.14

(1) Production costs, exclusive of workover costs, are costs incurred to operate and maintain wells and equipment and to pay production taxes.

Drilling Activity. The following table shows the Company's drilling activity for the last two years. During fiscal 1999 there was no drilling activity. "Gross" as it applies to wells refers to the number of wells in which a working interest is owned, while "net" applies to the sum of the fractional working interests in gross wells.

	Exploratory Wells Drilled				Developmental Wells Drilled			
	Productive		Dry		Productive		Dry	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
2001								
American Resources	-	-	1	0.06	1	0.1	-	-
Other	-	-	-	-	-	-	-	-
2000								
American Resources	3	0.091	0.07	4	0.19	1	0.05	
Other	-	-	-	-	-	-	-	-

The Company maintains a professional staff capable of supervising and coordinating the operation and administration of its oil and gas properties and pipeline and other assets. From time to time, major maintenance and engineering design and construction projects are contracted to third-party engineering and service companies.

Drillmar Project

In 2000, the Company, together with other partners, formed Drillmar, Inc., and owned a 37.5% interest. Drillmar has developed mooring solutions which allow a semi-submersible tender unit to be placed next to a deepwater floating production platform to assist the drilling and completion of oil and gas wells. Mono hull drilling tender barges were first utilized in the Gulf of Mexico in

the 1950's, whereby derrick equipment sets were placed on an offshore platform and operated from the tender barge. Due to significant weather down time, mono hull tender barges were eventually replaced in the Gulf of Mexico by new designs including self-erecting platform rigs and jack-up rigs. In the mid 1990's the first purpose built semi-tender was introduced in Malaysia. The performance in the South China Sea of semi-tender units was the basis for Drillmar's plan to utilize semi-tenders as a means to significantly reduce the cost of deepwater oil and gas development. Drillmar has developed a proprietary mooring solution and has patents pending to protect this technology. The semi-tender solution can also be applied to shallower water projects by providing customers high efficiency through its ability to mobilize or demobilize in less than twenty-four hours.

In 2000, Drillmar acquired a 1% general partner interest in Zephyr Drilling, Ltd., a Texas limited partnership ("Zephyr"). Zephyr owns a semi-submersible drilling rig that it acquired for approximately $7.6 million. At December 31, 2000, the Company's investment in Drillmar and the partnership consisted of $25,000 cash and the contribution of management and administrative services, estimated at $50,000.

In May 2001, the Company increased its ownership in Drillmar from 37.5% to 64%. Consideration paid by the Company included cash of approximately $131,000, and contribution of services in the amount of $434,000.

Effective January 2001, the Company entered into an agreement with Drillmar whereby it agreed to provide office space and certain management and administrative services to Drillmar for approximately $40,000 per month. The Company used the payments it is entitled to receive under this agreement to fund its investment in Drillmar. The funding of the Company's investment in Drillmar was completed in October 2001.

In September 2001, Drillmar entered into a merger agreement and merged with Zephyr. As a result of the merger, the Company's interest in Drillmar decreased from 64% to 12.8%.

Ivar Siem, Chairman of the Company, and Harris A. Kaffie, a director of the Company were limited partners of Zephyr. After the merger between Drillmar and Zephyr, Messrs Siem and Kaffie were owners of 30.3% and 30.6%, respectively, of Drillmar's common stock. During 2001, Messrs. Siem and Kaffie provided funding to Drillmar of $525,000 and $425,000, respectively, and were issued unsecured promissory notes from Drillmar. The promissory notes are due June 30, 2002 and bear interest at the rate of 10% per annum. Along with the promissory notes, Drillmar issued detachable warrants to Messrs. Siem and Kaffie of 52,500 and 42,500, respectively. Each warrant provides for the purchase of one share of Drillmar's common stock at $5 per share and are exercisable through January 31, 2005.

The Company records its investment in Drillmar using the equity method of accounting due to the Company providing management services to Drillmar. Under the equity method, investments are recorded at cost plus the Company's equity in undistributed earnings and losses after acquisition. Intercompany gains and losses are eliminated.

Pipeline Operations and Activities

The Company's pipeline assets are held and operations conducted by Blue Dolphin Pipe Line Company. Effective January 1, 2002, Mission Energy and Buccaneer Pipe Line, who held pipeline assets, were merged into Blue Dolphin Pipe Line Company, where all of the Company's pipeline assets are now held.

Blue Dolphin Pipeline System. As of December 31, 2001 the Company, through Blue Dolphin Pipe Line Company, owned a 50% undivided interest in the Blue Dolphin Pipeline System (the "Blue Dolphin System"), which, as a result of a recent acquisition, increased to an 83% interest in 2002. The Blue Dolphin

System includes the Blue Dolphin Pipeline, Buccaneer Pipeline, onshore facilities for condensate and gas separation and dehydration, 85,000 Bbls of above-ground tankage for storage of condensate, a barge loading terminal on the Intracoastal Waterway and 360 acres of land in Brazoria County, Texas where the Blue Dolphin Pipeline comes ashore and where the pipeline system shore facilities, pipeline easements and rights-of-way are located.

The Blue Dolphin System gathers and transports gas and condensate from various offshore fields in the Galveston Area in the Gulf of Mexico to shore facilities located in Freeport, Texas. After processing, the gas is transported to an end user and a major intrastate pipeline system with further downstream tie-ins to other intrastate and interstate pipeline systems and end users. The Buccaneer Pipeline, an 8" condensate pipeline, transports condensate from the storage tanks to the Company's barge loading terminal on the Intracoastal Waterway near Freeport, Texas for sale to third parties.

The Blue Dolphin Pipeline consists of two segments. The offshore segment transports both gas and condensate and is comprised of approximately 34 miles of 20-inch pipeline from a platform in Galveston Area Block 288 to shore. An additional 4 miles of 20 inch pipeline connect the offshore segment to the shore facility at Freeport, Texas. In 2001, Blue Dolphin Pipe Line Company installed a platform in Galveston Area Block 288 to operate and maintain the Blue Dolphin Pipeline System as a result of the Company's decision to abandon and remove the Buccaneer Field platforms in Galveston Area Blocks 288 and 296, which were previously used to operate and maintain the Blue Dolphin Pipeline System. The installation of the platform and its connection to the Blue Dolphin Pipeline System cost approximately $1.7 million net to the Company's 50% interest. Additionally, the offshore segment includes 5 field gathering lines totaling approximately 27 miles, connected to the main 20-inch line. This system's onshore segment consists of approximately 2 miles of 16-inch pipeline for transportation of gas from the shore facility to a sales point at a Freeport, Texas chemical plants' complex and intrastate pipeline system tie-in.

Various fees are charged to producer/shippers for provision of transportation and shore facility services. Blue Dolphin System gas throughput averaged approximately 16% of capacity during 2001. Current system capacity is approximately 160 MMcf per day of gas and 7,000 Bbls per day of condensate. During 2001, 100% of gas and condensate volumes transported were attributable to production from third party producer/shippers. See Note 12 to Consolidated Financial Statements included in Item 7.

Black Marlin Pipeline System. In January 2001, the Company and its partners, MCNIC and WBI Holdings, Inc. ("WBI") sold the Black Marlin Pipeline System and the High Island Block A-5 pipeline to Williams Field Services for $9.3 million. The Company through wholly-owned subsidiaries owned a 50% interest in these assets and received $4.6 million for its interest. The Black Marlin Pipeline System included the Black Marlin Pipeline, onshore facilities for condensate and gas separation and dehydration, 3,000 Bbls of above ground tankage for storage of condensate, a truck loading facility for oil and condensate, and five acres of land in Galveston County, Texas where the Black Marlin Pipeline comes ashore and on which are located the pipeline system's shore facilities.

Various fees were charged during 2000 to producer/shippers for provision of transportation and shore facility services. Black Marlin Pipeline System gas throughput averaged approximately 46% and 28% of capacity during 2000 and 1999, respectively. Black Marlin Pipeline System capacity is approximately 200 MMcf per day of gas and 1,500 Bbls per day of condensate. During 2000 and

1999, all gas and condensate volumes were attributable to production from third party producer/shippers.

In July 2000, the Company reached an agreement to provide transportation services for Vastar Resources, Inc. in High Island Area Block A-5, offshore Texas in the Gulf of Mexico. To accommodate this production, the

Company constructed a 3.4 mile 12" diameter pipeline from the production platform in High Island Area Block A-5 to the Black Marlin Pipeline. The cost to construct the pipeline was approximately $1.9 million, $.9 million net to the Company's 50% interest in the pipeline. The pipeline was completed in September 2000.

Other. In July 2000, the Company acquired an 83% ownership interest in an 8-inch, 12.78 mile pipeline extending from Galveston Area Block 350 to an interconnect to a transmission pipeline in Galveston Area Block 391 (the "GA350 Pipeline"), approximately 14 miles south of the Company's Blue Dolphin Pipeline for $224,000. The pipeline currently transports approximately 3,000 Mcf of gas per day. WBI acquired the remaining 17% interest in this pipeline.

The Company also holds an 83% undivided interest in the currently inactive Omega Pipeline. WBI holds a 17% interest. The Omega Pipeline originates in West Cameron Block 342 and extends to High Island Area, East Addition Block A-173, where it was previously connected to the High Island Offshore System ("HIOS"). The line could either be reconnected to HIOS, or a lateral pipeline could be constructed connecting into the Black Marlin Pipeline, approximately 14 miles to the west. Reactivation of the Omega Pipeline will be dependent upon future drilling activity in the vicinity and successfully attracting reserves to the system.

The economic return to the Company on its pipeline system investments is solely dependent upon the amounts of gas and condensate gathered and transported through the pipeline systems. Competition for provision of gathering and transportation services, similar to those provided by the Company, is intense in the market areas served by the Company. See Competition below. Since contracts for provision of such services between the Company and third party producer/shippers are generally for a specified time period, there can be no assurance that current or future producer/shippers will not subsequently tie-in to alternative transportation systems or that current rates charged by the Company will be maintained in the future. The Company actively markets gathering and transportation services to prospective third party producer/shippers in the vicinity of its pipeline systems. Future utilization of the pipelines and related facilities will depend upon the success of drilling programs around the pipelines, and attraction, and retention, of producer/shippers to the systems.

Midstream Development Projects

Offshore Crude Oil Terminalling

The Company's investment in and development of offshore crude oil terminals is through Petroport, Inc. Petroport, Inc. holds proprietary technology, represented by certain patents issued and or pending, associated with the development and operation of a deepwater crude oil and products terminal and offshore storage facility.

The Company's efforts have focused on two prospective market areas for locating such a facility: the Greater Houston area, including the Freeport, Texas and Houston Ship Channel market (the "Petroport" project); and the

Beaumont - Port Arthur, Texas and Westlake - Lake Charles, Louisiana market (the "Sabine Seaport" project).

The Company's efforts to advance its Petroport and Sabine Seaport projects has centered on development of market support, evidenced by firm throughput commitments to use the facilities when completed, and attracting partners to participate in and bear the development costs of these projects. The Company has actively been soliciting major oil companies that import large volumes of crude oil, and various other entities to participate in the ownership and further costs of project development. Uncertainties associated with recent and anticipated industry consolidations, the extent of displacement of long haul

imported barrels by future deepwater Gulf of Mexico production, and onshore logistics considerations, have resulted in the deferring of throughput commitment decisions by refiners from whom the Company has sought long term commitments for these projects.

Given the current lack of market support for the projects, which support is not expected over the next twelve months, the Company has elected to record a full impairment of $1.9 million of its investment in both the Petroport and Sabine Seaport projects. The Company, however, will continue market surveillance activities and seek prospective partners to jointly develop an offshore terminal project, if market conditions warrant such development in the future.

Avoca Gas Storage Project

In November 1999, the Company and WBI formed New Avoca Gas Storage, LLC ("New Avoca"), 25% owned and managed by the Company and 75% owned by WBI, and acquired the assets of Avoca Gas Storage, Inc. The Company records its investment in New Avoca by using the equity method of accounting.

The Avoca salt cavern gas storage project was conceived as a 5 Bcf working gas storage facility located south of Rochester near the town of Avoca, New York. Its design provides for 250 Mmcf per day injection and 500 Mmcf per day withdrawal capacities, with deliveries into the Tennessee Gas Pipeline HC400 24" line and other area transmission lines.

The original owner, Avoca Gas Storage, Inc., filed for bankruptcy on July 7, 1997. The assets were subsequently acquired out of bankruptcy by Northeastern Gas Caverns ("Northeastern"). In November 1999, the Company and WBI acquired the Avoca gas storage assets for $400,000 ($100,000 net to the Company's interest) from Northeastern. Additionally, a contingent payment of $.5 million ($125,000 net to the Company's interest) was due to Northeastern on May 22, 2000. New Avoca made a payment of $50,000 and extended the remaining $450,000 payment to August 22, 2000. In August 2000, Northeastern extended the contingent payment until October 2000 in exchange for increasing the contingent payment by $10,000 to $460,000. The contingent payment would be excused if Northeastern successfully settled a claim associated with Avoca Gas Storage, Inc. (the original owner of the Avoca gas storage assets). In October 2000, Northeastern received a payment on its claim and refunded $40,000 previously paid by New Avoca. New Avoca can elect to liquidate the project at any time.

The existing New Avoca assets include:

- Approximately 900 acres of land
- Pumps and pipeline for fresh water
- Pump house containing 12 pumps (6,400 HP) for the solution mining operation

- 9 cavern wells - 4,000' deep
- 6 brine disposal wells - 9,000' deep
- Storage building with valves, fittings, and miscellaneous parts
- Electrical switch gear
- Solution mining equipment
- Compressor foundations
- Electrical Sub-Station

To create the salt caverns for storage of gas, fresh water is injected from the surface to dissolve the salt formations below. The brine solution produced by this process must be continuously brought to the surface and then injected into underground disposal wells or disposed of in some other manner. The disposal wells must have sufficient porosity and permeability to accept the injected brine at a rate at least consistent with the rate at which brine is being produced during the creation of the salt caverns. The original owners of

the Avoca gas storage assets conducted tests to determine the rate that the disposal wells would accept brine. New Avoca believes that the testing procedures used by the original owners of the project to analyze the rate at which the disposal wells could accept brine may have been flawed as a result of the accelerated pace at which the tests were conducted, and therefore yielded test results that were uncertain and did not conclusively support an acceptable rate of brine disposal. The original owners of the Avoca gas storage assets encountered technical and other difficulties as a result of the uncertainty of their test results. New Avoca is reviewing additional brine disposal options that could be used to accelerate the creation of the salt caverns.

During 2000, New Avoca completed an analysis of the project. Based on this analysis and recent technological advances, New Avoca believes the disposal wells will be capable of handling the more moderate rates of brine injection expected to be produced under its proposed construction schedule. From October 2000 through February 10, 2001, New Avoca tested the disposal wells to determine the rate that these wells will accept brine. On February 12, 2001, as a result of mild seismic activity in the area surrounding Avoca, the New York State Department of Environmental Conservation requested that New Avoca stop testing the disposal wells. New Avoca stopped testing the wells, and does not plan on further testing at this time. As a viable solution to the brine disposal, New Avoca has studied the construction of a brine pipeline to deliver brine to a salt plant. New Avoca believes that a combination of the use of disposal wells and brine deliveries by pipeline appears to be the most feasible means of brine disposal. Efforts are underway to negotiate agreements with area salt plants to take the brine. Simultaneously, efforts to attract an additional equity partner are also being pursued. If a partner is obtained to acquire an equity interest in the project, New Avoca will proceed with permitting and preliminary engineering. New Avoca estimates that it will take between 9 months to 15 months for approval of its permit, and between 21 months to 2 years after approval of its permit to contract and begin operations at partial capacity, with another 2 years needed to complete construction and reach the full 5 BCF capacity. If New Avoca can not attract an equity partner, other financing must be obtained to proceed with the project. There can be no assurance that New Avoca will be able to attract new investors or obtain additional financing necessary to proceed with the project.

Customers

The Company generates revenues from both of its primary business segments. Revenues from major customers exceeding 10% of revenues were as follows for 2001. In 2000, no customer accounted for more than 10% of the

Company's total revenues.

	Oil and gas sales and operating fees	Pipeline operations	Total
Year ended December 31, 2001:			
Houston Exploration	$ --	639,975	639,975

Competition

The oil and gas industry is highly competitive in all segments. Increasingly vigorous competition occurs among oil, gas and other energy sources, and between producers, transporters, and distributors of oil and gas. Competition is particularly intense with respect to the acquisition of desirable producing properties and the marketing of oil and gas production. There is also competition for the acquisition of oil and gas leases suitable for exploration and for the hiring of experienced personnel to manage and operate the Company's assets. Several highly competitive alternative transportation and delivery options exist for current and potential customers of the Company's traditional gas and oil gathering and transportation business as well as for refiners,

shippers, marketers and producers of crude oil whom the Company's proposed Petroport and Sabine Seaport facilities would serve. Gas storage customers who would use the proposed Avoca Gas Storage system have alternatives, including depleted reservoir and other salt cavern storage systems. Competition also exists with other industries in supplying the energy and fuel needs of consumers.

Markets

The availability of a ready market for gas and oil, and the prices of such gas and oil, depends upon a number of factors, which are beyond the control of the Company. These include, among other things, the level of domestic production, actions taken by foreign oil and gas producing nations, the availability of pipelines with adequate capacity, the availability of vessels for direct shipment, lightering and transshipment and other means of transportation, the availability and marketing of other competitive fuels, fluctuating and seasonal demand for oil, gas and refined products, and the extent of governmental regulation and taxation (under both present and future legislation) of the production, importation, refining, transportation, pricing, use and allocation of oil, gas, refined products and alternative fuels.

Accordingly, in view of the many uncertainties affecting the supply and demand for crude oil, gas and refined petroleum products, it is not possible to predict accurately the prices or marketability of the gas and oil produced for sale or prices chargeable for transportation, terminalling and storage services, which the Company provides or may provide in the future.

Governmental Regulation

The production, processing, marketing, and transportation of oil and gas, and the development of terminalling and storage of crude oil and gas by the Company are subject to federal, state and local regulations which can have a significant impact upon the Company's overall operations.

Federal Regulation of Natural Gas Transportation. The transportation and resale of gas in interstate commerce have been regulated by the Natural Gas Act, the Natural Gas Policy Act and the rules and regulations promulgated by FERC. In the past, the federal government has regulated the prices at which gas could be sold. In 1989, Congress enacted the Natural Gas Wellhead Decontrol Act, which removed all remaining Natural Gas Act and Natural Gas Policy Act price and non-price controls affecting producer sales of gas, effective January 1, 1993. Congress could, however, reenact price controls in the future.

The price and terms for access to pipeline transportation is subject to extensive federal regulation. In April 1992, the FERC issued Order No. 636, beginning a series of related orders, which required interstate pipelines to provide open-access transportation on a basis that is equal for all gas suppliers. The FERC has stated that it intends Order No. 636 to foster increased competition within all phases of the gas industry. Order No. 636 affects how buyers and sellers gain access to the necessary transportation facilities and how gas is sold in the marketplace. In 2000, the FERC issued Order No. 637 which, among other things, will permit pipelines to file for peak/off-peak and term differentiated rate structures and changed existing regulations relating to scheduling procedures, capacity segmentation, pipeline imbalance processes and penalties, and pipeline reporting requirements.

The Company cannot predict whether the FERC's actions will achieve the goal of increasing competition in the gas markets or how these, or future regulations will affect its operations or competitive position. However, the Company does not believe that any action taken will affect it in any way that materially differs from the way that such action affects the Company's competitors.

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Of the gas pipelines owned by the Company in 2001, only the Black Marlin Pipeline (sold in January 2001) was subject to rules and regulations of the Natural Gas Act. As a result, its gas transportation service and pricing service were subject to the regulatory jurisdiction of the FERC.

All of the Company's pipelines located offshore in federal waters are subject to the requirements of the Outer Continental Shelf Lands Act ("OCSLA"). FERC has stated that nonjurisdictional gathering lines, as well as interstate pipelines, are fully subject to the open access and nondiscrimination requirements of OCSLA's Section 5, which generally authorizes the FERC to insure that gas pipelines on the Outer Continental Shelf will transport for non-owner shippers in a nondiscriminatory manner and will be operated in accordance with certain pro-competitive principles. More recently, the FERC has undertaken several investigations into the nature and extent of its regulatory powers on the Outer Continental Shelf. It issued a policy statement on Outer Continental Shelf pipelines reaffirming the requirement that all pipelines provide nondiscriminatory service. In 2000, FERC issued Order 639, formally imposing new OCSLA regulations on offshore pipelines not otherwise subject to its Natural Gas Act jurisdiction. Order 639's requirements, which largely entail reporting and disclosure obligations to FERC, contain certain exemptions for, among other things, an offshore pipeline system that "feeds into a facility where gas is first collected or a facility where gas is first separated, dehydrated, or otherwise processed."

Further FERC initiatives concerning possibly diminished Natural Gas Act regulation of pipelines on the OCS and/or broader regulation under the OCSLA remain possible and could cause increased regulatory compliance costs. Since all of the Companies' offshore pipelines fall within the exemption for feeder facilities and already operate on the basis required under OCSLA, the Company does not anticipate significant changes directly resulting from requirements concerning nondiscriminatory open access transportation. Moreover, if an offshore pipeline's throughput increases to the extent that the pipeline's capacity is completely utilized, under OCSLA, the FERC may be petitioned to direct capacity allocation on the pipeline. Accordingly, the Company cannot predict how application of the OCSLA to its pipelines may ultimately affect Company operations.

Aside from the OCSLA requirements and federal safety and operational regulations, regulation of gas gathering activities is primarily a matter of state oversight. Regulation of gathering activities in Texas includes various transportation, safety, environmental and non-discriminatory purchase/transport requirements.

Federal Regulation of Oil Pipelines. The Company's operation of the Buccaneer Pipeline is subject to a variety of regulations promulgated by the FERC and imposed on all oil pipelines pursuant to federal law. In particular, the rates chargeable by the Company are subject to prior approval by the FERC, as are operating conditions and related matters contained in the Company's transportation tariffs which are on file with the FERC. In 1993, the FERC issued Order No. 561, which was intended to simplify oil pipeline ratemaking, largely through use of a ceiling based on an indexing system. At the end of 2000, the Commission issued an order based on a five-year review of the indexing system, affirming this approach to oil pipeline ratemaking. Because Buccaneer Pipeline has not taken action to become subject to Order No. 561 or Order No. 572 concerning market-based rates for oil pipelines, the Company cannot predict whether or how an indexed or market-based rate system will affect the Buccaneer Pipeline's rates.

Safety and Operational Regulations. The operations of the Company are generally subject to safety and operational regulations administered primarily by the MMS, the U.S. Department of Transportation, the U.S. Coast Guard, the FERC and/or various state agencies. Currently, the Company believes that it is

in material compliance with the various safety and operational regulations that it is subject to. However, as safety and operational regulations are frequently changed, the Company is unable to predict the future effect changes in these regulations will have on its operations, if any.

Regulation of Deepwater Ports: Permitting and Licensing. The ownership, construction and operation of a deepwater crude oil terminal facility (a "Deepwater Port"), such as the Company's proposed Petroport and Sabine Seaport facilities, must conform to the requirements of a number of federal, state and local laws. A license from the Department of Transportation ("DOT") is required under the Deepwater Port Act of 1974 ("DWPA"), as amended. Permits from the Environmental Protection Agency and the Federal Communication Commission are required, as well as permits from the U.S. Army Corps of Engineers and the State of Texas to construct ancillary port facilities, such as pipelines and onshore facilities.

The DWPA empowers the Secretary of Transportation to license and regulate Deepwater Ports beyond the territorial sea of the United States. License applications must include sufficient information to allow the Secretary of Transportation to judge whether a Deepwater Port will comply with all technical, environmental, and economic criteria. The application and licensing process includes the preparation of an Environmental Impact Statement, development of detailed operations procedures, submission of extensive financial and ownership data and public hearings.

The Company was a principal participant in the development and passage of The Deepwater Port Modernization Act in 1996, successfully amending the DWPA. The amendments to the Deepwater Port Act provide: (1) upon written request of an applicant for a license, the Secretary may exempt the applicant from certain of the informational filing requirements if the Secretary determines such information is not necessary to facilitate his or her determination and such exemption will not limit public review; (2) the facility is explicitly permitted to receive domestic production from the United States Outer Continental Shelf; (3) simplification and streamlining of the regulatory process to which the facility would be subject during both the licensing process and when in operation; and (4) elimination of various facility use restrictions. Once a license is issued, it remains in effect unless suspended or revoked by the Secretary of Transportation or is surrendered by the licensee.

Regulations provide for extensive consultation among all interested federal agencies, any potentially affected coastal state, and the general public. Adjacent coastal states are granted an effective veto power or reservation over proposed Deepwater Ports. The Secretary of Transportation will not issue a license without the approval of the governor of each adjacent coastal state. Under the statute, if a Governor of an adjacent coastal state notifies the Secretary of Transportation that a proposal is inconsistent with the state programs relating to environmental protection, land and water use, and coastal zone management, then the Secretary of Transportation shall grant the license on the condition that the proposal is made consistent with such state programs. Governors may, in their discretion, also reject proposed Deepwater Ports on other grounds.

In addition, the DWPA requires all Deepwater Ports, including related storage facilities, be operated as common carriers. As a common carrier the Company's proposed Petroport and Sabine Seaport facilities would be required to accept, transport or convey all oil delivered, unless it is subject to "effective competition" from alternative transportation systems.

Given the nature and complexity of obtaining the necessary license and permits, there can be no assurance that the Company would be issued a Deepwater Port license and other necessary permits, if such are sought.

Federal Oil and Gas Leases. The Company's operations on offshore federal oil and gas leases under the OCSLA must be conducted in accordance with permits issued by the MMS and are subject to a number of other regulatory restrictions similar to those imposed by the states.

The Company's leases in the OCS provide for royalty payments on gas production calculated at some fraction of the value of the gas produced. OCS lessees have challenged the Department of Interior's rules and regulations which prohibit the natural gas producer from subtracting downstream marketing costs from royalties owed to the Federal government. The U.S. Court of Appeals for the District of Columbia on February 8, 2002 reversed the U.S. District Court for the District of Columbia and upheld the Department of Interior's rule that producers may not deduct costs such as downstream marketing costs, including aggregator/marketing fees or intra-hub transfer fees charged by pipelines to track paper transactions at a pipeline junction (not for physical transfers).

With respect to any Company operations conducted on offshore federal leases, liability may generally be imposed under OCSLA for costs of clean-up and damages caused by pollution resulting from such operations, other than damages caused by acts of war or the negligence of third parties. Under certain circumstances, including but not limited to conditions deemed a threat or harm to the environment, the MMS may also require any Company operations on federal leases to be suspended or terminated in the affected area. Furthermore, the MMS generally requires that offshore facilities be dismantled and removed within one year after production ceases or the lease expires.

Environmental Regulation. The Company's activities with respect to (1) exploration, development and production of oil and natural gas and (2) the operation and construction of pipelines, plants, and other facilities for the transportation and processing, and storage of crude oil, natural gas and natural gas liquids are subject to stringent environmental regulation by local, state and federal authorities, including the U.S. Environmental Protection Agency ("EPA"). Such regulation has increased the cost of planning, designing, drilling, operating and in some instances, abandoning wells and related equipment. Similarly, such regulation has also increased the cost of design, construction, and operation of crude oil and natural gas pipelines and processing facilities. Although the Company believes that compliance with existing environmental regulations will not have a material adverse affect on operations or earnings, there can be no assurance that significant costs and liabilities, including civil and criminal penalties, will not be incurred. Moreover, future developments, such as stricter environmental laws and regulations or claims for personal injury or property damage resulting from the Company's operations, could result in substantial costs and liabilities. It is not anticipated that, in response to such regulation, the Company will be required in the near future to expend amounts that are material relative to its total capital structure. However, it is possible that the costs of compliance with environmental and health and safety laws and regulations will continue to increase. Given the frequent changes made to environmental and health and safety regulations and laws, the Company is unable to predict the ultimate cost of compliance.

The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA") imposes liability, without regard to fault or the legality of the original conduct, on responsible parties with respect to the release or threatened release of a "hazardous substance" into the environment. Responsible parties, which include the owner or operator of a site where the release occurred and persons that disposed or arranged for the disposal of a hazardous substance at the site, are liable for response and remediation costs and for damages to natural resources. Petroleum and natural gas are excluded from the definition of "hazardous substances;" however, this exclusion does not apply to all materials associated with the production of petroleum or natural gas. At this time, neither the Company nor any of its predecessors has been designated as a potentially responsible party under CERCLA.

The federal Resource Conservation and Recovery Act ("RCRA") and its state counterparts regulate solid and hazardous wastes and impose civil and criminal penalties for improper handling and disposal of such wastes. EPA and

various state agencies have promulgated regulations that limit the disposal options for such wastes. Certain wastes generated by the Company's oil and gas operations are currently exempt from regulation as "hazardous wastes," but in the future could be designated as "hazardous wastes" under RCRA or other applicable statutes and therefore may become subject to more rigorous and costly requirements.

The Company currently owns or leases, or has in the past owned or leased, numerous properties used for the exploration and production of oil and gas or used to store and maintain equipment regularly used in these operations. Although the Company's past operating and disposal practices at these properties were standard for the industry at the time, hydrocarbons or other substances may have been disposed of or released on or under these properties or on or under other locations. In addition, many of these properties have been operated by third parties whose waste handling activities were not under the Company's control. These properties and any waste disposed thereon may be subject to CERCLA, RCRA, and analogous state laws which could require the Company to remove or remediate wastes and other contamination or to perform remedial plugging operations to prevent future contamination.

The Oil Pollution Act of 1990 ("OPA") and regulations promulgated thereunder include a variety of requirements related to the prevention of oil spills and impose liability for damages resulting from such spills. OPA imposes liability on owners and operators of onshore and offshore facilities and pipelines for removal costs and certain public and private damages arising from a spill. OPA establishes a liability limit for onshore facilities of $350 million and for offshore facilities of all removal costs plus $75 million, and lesser liability limits for vessels depending upon their size. In August 1995, the DOT issued a Rulemaking under OPA providing that the Secretary of Transportation can set the liability limit and associated Certificate of Financial Responsibility requirement for Deepwater Ports from between $350.0 million and $50.0 million concurrent with the overall processing of the DWPA license application. Development of the liability limit would be based upon engineering and environmental analysis provided during the licensing process. A party cannot take advantage of the liability limits if the spill is caused by gross negligence or willful misconduct or resulted from a violation of federal safety, construction, or operating regulations. If a party fails to report a spill or cooperate in the cleanup, liability limits likewise do not apply. OPA imposes ongoing requirements on responsible parties, including proof of financial responsibility for potential spills. The amount of financial responsibility required depends upon a variety of factors including the type of facility or vessel, its size, storage capacity, oil throughput, proximity to sensitive areas, type of oil handled, history of discharges, worst-case spill potential and other factors. The Company believes it has established adequate financial responsibility. While the financial responsibility requirements under OPA may be amended to impose additional costs on the Company, the impact of such a change is not expected to be any more burdensome on the Company than on others similarly situated.

The Clean Air Act and state air quality laws and regulations contain provisions that impose pollution control requirements on emissions to the air and require permits for construction and operation of certain emissions sources, including sources located offshore. The Company may be required to incur capital expenditures for air pollution control equipment in connection with maintaining or obtaining operating permits and approvals addressing emission-related issues, although the Company does not expect to be materially adversely affected by such expenditures.

The Clean Water Act ("CWA") regulates the discharge of pollutants to waters of the United States and imposes permit requirements on such discharges, including discharges to wetlands. Federal regulations under the CWA and OPA require certain owners or operators of facilities that store or otherwise handle oil, to prepare and implement spill prevention, control and countermeasure plans

and facility response plans relating to the possible discharge of oil into surface waters. With respect to certain of the Company's operations, it is required to prepare and comply with such plans and to obtain and comply with permits. The CWA also prohibits spills of oil and hazardous substances to waters of the United States in excess of levels set by regulations and imposes liability in the event of a spill. State laws further provide varying civil and criminal penalties and liabilities for the spills to both surface and groundwaters. The Company believes it is in substantial compliance with the requirements of the CWA, OPA, and state laws, and that any non-compliance would not have a material adverse effect on the Company.

Legislation and Rulemaking. In October 1996 the U.S. Congress enacted the Coast Guard Authorization Act of 1996 (P.L. 104-324) which amended the OPA to establish requirements for evidence of financial responsibility for certain offshore facilities, other than Deepwater Ports. The amount required is $35.0 million for certain types of offshore facilities located seaward of the seaward boundary of a state, including properties used for oil transportation. The Company currently maintains this statutory $35.0 million coverage.

Federal and state legislative rules and regulations are pending that, if enacted, could significantly affect the oil and gas industry. It is impossible to predict which of those federal and state proposals and rules, if any, will be adopted and what effect, if any, they would have on the operations of the Company.

In addition, various federal, state and local laws and regulations covering the discharge of materials into the environment, occupational health and safety issues, or otherwise relating to the protection of public health and the environment, may affect the Company's operations, expenses and costs. The trend in such regulation has been to place more restrictions and limitations on activities that may impact the general or work environment, such as emissions of pollutants, generation and disposal of wastes, and use and handling of chemical substances. It is not anticipated that, in response to such regulation, the Company will be required in the near future to expend amounts that are material relative to its total capital structure. However, it is possible that the costs of compliance with environmental and health and safety laws and regulations will continue to increase. Given the frequent changes made to environmental and health and safety regulations and laws, the Company is unable to predict the ultimate cost of compliance.

RISK FACTORS

Oil and gas prices are volatile and a substantial and extended decline in the price of oil and gas would have a material adverse effect on the Company.

The Company's revenues, profitability, operating cash flow, the carrying value of its oil and gas properties and its potential for growth are largely dependent on prevailing oil and gas prices. Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply and demand for oil and gas, uncertainties within the market and a variety of other factors beyond the Company's control. These factors include:

- weather conditions in the United States;
- the condition of the United States economy;
- the actions of the Organization of Petroleum Exporting Countries;
- governmental regulation;

- political stability in the Middle East and elsewhere;
- the foreign supply of oil and gas;
- the price of foreign imports; and
- the availability of alternate fuel sources.

In addition to decreasing the Company's revenue and operating cash flow, low or declining oil and gas prices could have collateral effects that could adversely affect the Company, including the following:

- reducing the overall volumes of oil and gas that the Company can produce from its oil and gas reserves economically;
- resulting in an impairment to the historical carrying value of the Company's oil and gas properties, which could compel the Company, under generally accepted accounting principles, to recognize a significant write down of the carrying value of its oil and gas assets on its balance sheet and an associated charge to its income;
- increasing the Company's dependence on external sources of capital to meet its cash needs; and
- impairing the Company's ability to obtain needed equity.

Volatile oil and gas prices also make it difficult to estimate the value of producing properties the Company may acquire and also make it difficult for the Company to budget for and project the return on acquisitions and development and exploitation projects.

An adverse result from the H&N Gas litigation could effect the Company's financial condition.

If American Resources experiences an adverse outcome with respect to the H&N Gas litigation, American Resources' ability to contribute to the Company's consolidated financial operating results would be adversely affected. An adverse outcome could require the Company to fund the on-going operations and cash-flow needs of American Resources. Furthermore, if the H&N Gas litigation continues for a prolonged period the Company would incur significant legal expenses, which could have a material adverse effect on the Company's financial condition.

The Company may be subject to contractual penalties if it is unable to pay its share of drilling costs.

If the Company lacks and is unable to obtain cash sufficient to pay its proportionate share of the estimated costs to drill any well in which it owns less than 100% of the working interest, the Company may be subject to contractual "non-consent" and other penalties. These penalties may include, for example, full or partial forfeiture of the Company's interest in the well or a relinquishment of the Company's interest in production from the well in favor of the participating working interest owners until the participating working interest owners have recovered a multiple of the costs which would have been borne by the Company if it had elected to participate, which often ranges from 400% to 600% of such costs.

The Company faces strong competition from larger oil and gas companies that may negatively affect its ability to carry on operations.

The Company operates in a highly competitive industry. The Company's competitors include major integrated oil companies, substantial independent energy companies, affiliates of major interstate and intrastate pipelines and national and local gas gatherers, many of which possess greater financial and other resources than the Company. The Company's ability to successfully compete in the marketplace is affected by many factors.

- Most of the Company's competitors have greater financial resources than it does, which gives them better access to sources of capital to acquire and develop oil and gas properties.

- Most of the Company's competitors have longer operating histories and have more data generally available to them, including information relating to oil and gas properties.

- The Company often establishes a higher standard for the minimum projected rate of return on an investment than some of its competitors since it cannot afford to absorb certain risks. The Company believes this puts it at a competitive disadvantage in acquiring oil and gas properties.

The Company's future success depends, in part, upon its ability to find, develop and acquire additional oil and gas reserves that are economically recoverable.

The Company's proved reserves will decline as they are produced unless it conducts successful exploration or development activities or acquires properties containing proved reserves. The Company must attempt to increase its proved reserves even during periods of low oil and gas prices when it is difficult to raise the capital necessary to finance these activities. There can be no assurance that the Company's planned development projects and acquisition activities will result in significant increases in its reserves or that the Company will drill or participate in the drilling of productive wells at economic returns. The drilling of oil and gas wells involves a high degree of risk, especially the risk of dry holes or of wells that are not sufficiently productive to provide an economic return on the capital expended to drill the wells. The cost of drilling, completing and operating a well is uncertain, and the Company's drilling or production may be curtailed or delayed as a result of many factors.

Undue reliance should not be placed on reserve information because reserve information represents estimates.

This annual report includes estimates of the Company's oil and gas reserves and the future net revenues from those reserves which the Company and its independent petroleum consultants have prepared. Reserve engineering is a subjective process of estimating the Company's recovery from underground accumulations of oil and gas that cannot be measured in an exact manner. The accuracy of the Company's reserve estimates is a function of the quality of available data and of engineering and geological interpretation and judgment. Estimates of the Company's economically recoverable oil and gas reserves and of future net cash flows necessarily depend upon a number of variable factors and assumptions, such as:

- historical production from the area compared with production from other producing areas;

- the assumed effects of regulations by governmental agencies;

and

- assumptions concerning future oil and gas prices, future operating costs, severance and excise taxes, development costs and costs to restore or increase production on a producing well.

In addition, different reserve engineers may make different estimates of reserve quantities and cash flows based upon the same available data. The Company's reserve estimates are to some degree speculative. As a result there may be material variances between the Company's actual results and costs, and its estimates of:

- the quantities of oil and gas that the Company ultimately recovers;

- the Company's production and operating costs;

- the amount and timing of the Company's future development expenditures; and

- the Company's future oil and gas sales prices.

Any significant variance in these assumptions could materially affect the estimated quantity and value of the Company's reserves reported in this annual report.

The Company cannot control the activities on properties it does not operate.

Other companies operate many of the properties in which the Company has an interest. As a result, the Company will depend on the operator of the wells to properly conduct lease acquisition, drilling, completion and production operations. The failure of an operator, or the drilling contractors and other service providers selected by the operator to properly perform services, could adversely affect the Company, including the amount and timing of revenues it receives from its interest.

The Company has and generally anticipates that it will typically own substantially less than a 50% working interest in its prospects and will therefore engage in joint operations with other working interest owners. In instances in which the Company owns or controls less than a majority of the working interest in a prospect, decisions affecting the prospect could be made by the owners of more than a majority of the working interest. For instance, if the Company is unwilling or unable to participate in the costs of operations approved by a majority of the working interests in a well, the Company's working interest in the well (and possibly other wells on the prospect) will likely be subject to contractual "non-consent penalties" such as those described under the caption "The Company may be subject to contractual penalties if it is unable to pay its share of drilling costs."

The Company has pursued, and intends to continue to pursue, acquisitions. The Company's business may be adversely affected if it cannot effectively integrate acquired operations.

One of the Company's business strategies has been to acquire operations and assets that are complementary to its existing businesses. Acquiring operations and assets involves financial, operational and legal risks. These risks include:

- inadvertently becoming subject to liabilities of the acquired company that were unknown to the Company when it was acquired, such as later asserted litigation matters or tax liabilities,
- the difficulty of assimilating operations, systems and personnel of the acquired businesses, and

- maintaining uniform standards, controls, procedures and policies.

Any future acquisitions would likely result in an increase in expenses. In addition, competition from other potential buyers could cause the Company to pay a higher price than it otherwise might have to pay and reduce its acquisition opportunities. The Company is often out-bid by larger, more capitalized companies for acquisition opportunities it pursues. Moreover, the Company's past success in making acquisitions and in integrating acquired businesses does not necessarily mean it will be successful in making acquisitions and integrating businesses in the future.

Operating hazards including those peculiar to the marine environment may adversely affect the Company's ability to conduct business.

The Company's operations are subject to risks inherent in the oil and gas industry, such as:

- sudden violent expulsions of oil, gas and mud while drilling a well, commonly referred to as a blowout;
- a cave in and collapse of the earth's structure surrounding a well, commonly referred to as cratering;
- explosions;
- fires;
- pollution; and
- other environmental risks.

These risks could result in substantial losses to the Company from injury and loss of life, damage to and destruction of property and equipment, pollution and other environmental damage and suspension of operations. The Company's offshore operations are also subject to a variety of operating risks peculiar to the marine environment, such as hurricanes or other adverse weather conditions and more extensive governmental regulation. These regulations may, in certain circumstances, impose strict liability for pollution damage or result in the interruption or termination of operations.

Losses and liabilities from uninsured or underinsured drilling and operating activities could have a material adverse effect on the Company's financial condition and operations.

The Company maintains several types of insurance to cover its operations, including maritime employer's liability and comprehensive general liability. Amounts over base coverages are provided by primary and excess umbrella liability policies with maximum limits of $50.0 million. The Company also maintains operator's extra expense coverage, which covers the control of drilled or producing wells as well as redrilling expenses and pollution coverage for wells out of control.

The Company may not be able to maintain adequate insurance in the future at rates it considers reasonable or losses may exceed the maximum limits under the Company's insurance policies. If a significant event that is not fully insured or indemnified occurs, it could materially and adversely affect the Company's financial condition and results of operations.

Compliance with environmental and other government regulations could be costly and could negatively impact production and pipeline operations.

The Company's operations are subject to numerous laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may:

- require the acquisition of a permit before drilling commences;
- restrict the types, quantities and concentration of various substances that can be released into the environment from drilling and production activities;
- limit or prohibit drilling and pipeline activities on certain lands lying within wilderness, wetlands and other protected areas;
- require remedial measures to mitigate pollution from former operations, such as plugging abandoned wells and abandoning pipelines; and
- impose substantial liabilities for pollution resulting from the Company's operations.

The recent trend toward stricter standards in environmental legislation and regulation is likely to continue. The enactment of stricter legislation or the adoption of stricter regulation could have a significant impact on the Company's operating costs, as well as on the oil and gas industry in general.

The Company's operations could result in liability for personal injuries, property damage, oil spills, discharge of hazardous materials, remediation and clean-up costs and other environmental damages. The Company could also be liable for environmental damages caused by previous property owners. As a result, substantial liabilities to third parties or governmental entities may be incurred which could have a material adverse effect on the Company's financial condition and results of operations. The Company maintains insurance coverage for its operations, including limited coverage for sudden and accidental environmental damages, but the Company does not believe that insurance coverage for environmental damages that occur over time or complete coverage for sudden and accidental environmental damages is available at a reasonable cost. Accordingly, the Company may be subject to liability or may lose the privilege to continue exploration or production activities upon substantial portions of its properties if certain environmental damages occur.

The OPA imposes a variety of regulations on "responsible parties" related to the prevention of oil spills. The implementation of new, or the modification of existing, environmental laws or regulations, including regulations promulgated pursuant to the OPA, could have a material adverse impact on the Company.

GLOSSARY OF CERTAIN OIL AND GAS TERMS

The following are abbreviations and definitions of certain terms commonly used in the oil and gas industry.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil or other liquid hydrocarbons.

Bcf. One billion cubic feet of gas.

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Btu or British Thermal Unit. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Condensate. Liquid hydrocarbons associated with the production of a primarily gas reserve.

Development well. A well drilled within the proved area of a gas or oil reservoir to the depth of a stratigraphic horizon known to be productive.

Exploratory well. A well drilled to find and produce gas or oil in an unproved area, to find a new reservoir in a field previously found to be productive of gas or oil in another reservoir or to extend a known reservoir.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Leasehold interest. The interest of a lessee under an oil and gas lease.

MBbls. One thousand barrels of oil or other liquid hydrocarbons.

Mcf. One thousand cubic feet of gas.

Mcfe. One thousand cubic feet equivalent, determined using the ratio of six Mcf of gas to one barrel of oil, condensate or gas liquids.

Mmbtu. One million British Thermal Units.

Mmcf. One million cubic feet of gas.

Mmcfe. One million cubic feet equivalent, determined using the ratio of six Mcf of gas to one Bbl of oil, condensate or gas liquids.

Net revenue interest. The percentage of production to which the owner of a working interest is entitled.

Nonoperating working interest. A working interest, or a fraction of a working interest, in a tract where the owner is not the operator of the tract.

Overriding royalty. An interest in oil and gas produced at the surface, free of the expense of production that is in addition to the usual royalty interest reserved to the lessor in an oil and gas lease.

Prospect. A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of oil, gas or both.

Proved developed reserves. Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved developed reserves are further categorized into two sub-categories, proved developed producing reserves and proved developed non-producing reserves.

Proved developed producing. Reserves sub-categorized as producing are expected to be recovered from completion intervals which are open and producing at the time of the estimate.

Proved developed non-producing. Reserves sub-categorized as non-producing include shut-in and behind pipe reserves. Shut-in reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not started producing, (2) wells which were shut-in awaiting pipeline connections or as a result of a market interruption, or (3) wells not capable of producing for mechanical reasons.

Proved reserves. The estimated quantities of oil, gas and condensate that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Proved undeveloped reserves. Reserves that are expected to be recovered from new wells or from existing wells where a relatively major expenditure is required for recompletion.

Reversionary interest. A form of ownership interest in property that reverts back to the transferor after expiration of an intervening income interest or the occurrence of another triggering event.

Royalty interest. An interest in a gas and oil property entitling the owner to a share of gas and oil production free of costs of production.

Undivided Interest. A form of ownership interest in which more than one person concurrently owns an interest in the same oil and gas lease or pipeline.

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production.

Item 2. Properties

Information appearing in Item 1 describing the Company's oil and gas properties under the caption "Business and Properties" is incorporated herein by reference.

The Company leases its executive offices in Houston, Texas, under an operating lease expiring December 31, 2006. The Company also leases under an operating lease expiring April 30, 2002, a division office in New Orleans, Louisiana. The New Orleans office was closed in January 2002. The Company's aggregate annual lease payment obligations under these leases are $186,485.

Item 3. Legal Proceedings

On May 8, 2000, American Resources and its former Chief Financial Officer, were named in a lawsuit in the United States District Court for the Southern District of Texas, Houston Division, styled H&N Gas, Limited

Partnership, et al. v. Richard Hale, et al (Case No H-00-1371). The lawsuit alleges, among other things, that H&N Gas ("H&N") was defrauded by American Resources in connection with gas purchase options and gas price swap contracts entered into from February 1998 through September 1999. H&N alleges unlawful collusion between American Resources' prior management and the then president of H&N, Richard Hale ("Hale"), to the detriment of H&N. H&N generally alleges that Hale directed H&N to purchase illusory options from American Resources that bore no relation to any physical gas business and that American Resources did not have the financial resources and/or sufficient quantity of gas to perform. H&N further alleges that American Resources and Hale colluded with respect to swap

transactions that were designed to benefit American Resources at the expense of H&N Gas. H&N further alleges civil conspiracy against all the defendants. H&N is seeking approximately $6.2 million in actual damages plus treble damages, punitive damages and prejudgment interest against ARO directly. As a result of its conspiracy allegation, H&N also contends that all defendants are jointly and severally liable for over $40.0 million dollars in actual damages plus treble damages, punitive damages and prejudgment interest. American Resources intends to vigorously defend this claim.

Item 4. Submission of Matters to a Vote of Security Holders

The Company's annual meeting of shareholders was held on December 13, 2001. The matters that were voted upon at the meeting, and the number of votes cast for, against or withheld, as well as the number of abstentions and broker non-votes, as to such matters, where applicable, are set forth below.

	Votes For	Votes Against	Votes Withheld	Abstentions	Broker Non-Vot
Election of Directors					
Ivar Siem	3,051,097	16	1,883,819	0	1,080,79
Robert L. Barbanell	3,051,097	16	1,883,819	0	1,080,79
Michael S. Chadwick	3,051,097	16	1,883,819	0	1,080,79
Harris A. Kaffie	3,051,097	16	1,883,819	0	1,080,79
Robert D. Wagner	3,051,097	16	1,883,819	0	1,080,79

PART II

Item 5. Market for Registrant's Common Stock and Related Stockholder Matters

The Company's common stock trades in the over-the-counter market and is quoted on the NASDAQ Small Cap Market under the symbol "BDCO". As of March 22, 2002, there were an estimated 678 stockholders of record and the Company estimates there are more than 1,000 beneficial owners of its common stock. NASDAQ quotations reflect inter-dealer prices, without adjustment for retail mark-ups, markdowns or commissions and may not represent actual transactions. The following table sets forth, for the periods indicated, the high and low bid price for the common stock as reported by the NASDAQ.

	High	Low

Quarter Ended March 31, 2000	$ 6.38	$ 5.00
Quarter Ended June 30, 2000	$ 6.13	$ 4.50
Quarter Ended September 30, 2000.............	$ 5.56	$ 2.75
Quarter Ended December 31, 2000	$ 5.56	$ 2.50
Quarter Ended March 31, 2001	$ 5.19	$ 3.25
Quarter Ended June 30, 2001	$ 4.95	$ 3.80
Quarter Ended September 30, 2001.............	$ 4.31	$ 2.81
Quarter Ended December 31, 2001	$ 3.40	$ 1.60

The Company has not declared or paid any dividends on the Common Stock since its incorporation. The Company currently intends to retain earnings for its capital needs and expansion of its business and does not anticipate paying cash dividends on the Common Stock in the foreseeable future. Previously, the Company was restricted, pursuant to its loan agreement from paying dividends on the Common Stock if there was an outstanding balance under the loan agreement. Any loan agreements which the Company may enter into in the future will likely contain restrictions on the payment of dividends on its' Common Stock. Future

policy with respect to dividends will be determined by the Board of Directors based upon the Company's earnings and financial condition, capital requirements and other considerations. The Company is a holding company that conducts substantially all of its operations through its' subsidiaries. As a result, the Company's ability to pay dividends on the Common Stock is dependent on the cash flow of its subsidiaries.

Item 6. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following is a review of certain aspects of the financial condition and results of operations of the Company and should be read in conjunction with the Consolidated Financial Statements included in Item 7 and Item 1. Business.

Anticipated Cash Requirements

Historically, the Company has relied on the proceeds from the sale of assets and capital raised from the issuance of debt and equity securities to individual investors and related parties to sustain its operations. The Company incurred net losses of $2,649,142 and $10,135,120 during the years ended December 31, 2001 and 2000, respectively. Recent losses have resulted in an accumulative deficit of $21,021,859 at December 31, 2001. The Company also has a working capital deficiency of approximately $1.2 million. These factors combined with the cash requirements inherent in the Company's businesses raise substantial doubt about its ability to continue as a going concern. The Company's long-term viability as a going concern is dependent upon the following key factors as follows:

- Its ability to raise capital to meet current commitments and fund the continuation of our business operations; and

- Its ability to ultimately achieve profitability and cash flows from operations in amounts that will sustain its operations.

The following are summaries of certain of the Company's contractual cash obligations and other commercial cash commitments at December 31, 2001 (amounts in thousands).

Contractual Obligations	Total	Payments Due by Period Less than 1 year	1-3 years	4-5 years	After 5 years
Long-Term Debt	$ --	--	--	--	--
Other Contractual Obligations	5,059	2,986	1,877	196	--
Total Contractual Cash Obligations	$ 5,059	2,986	1,877	196	--

Other Commercial Commitments	Total	Amount of Commitment Expiration Per Period Less than 1 year	1-3years	4-5 years	After 5 years
Long-Term Debt	$ --	--	--	--	--
Other Commercial Obligations	2,000	2,000	--	--	--
Total Commercial Cash Obligations	$ 2,000	2,000	--	--	--

Prior to the decrease in production in the High Island A-7 field and the corresponding delay in the Company's receipt of revenues from its reversionary working interest in this field, the Company believed that it would have adequate capital to meet its obligations and operating needs for 2002. However, due to the occurrence of these events, the Company believes that it will need to raise between $2.0 and $3.0 million of capital to meet its obligations and working capital requirements in fiscal 2002. The Company will have to either:

- sell assets;
- seek external financing by issuing equity or debt securities; or,
- a combination of the above.

There can be no assurance that the Company will be able to raise additional capital or that it will be able to raise additional capital on commercially acceptable terms. The Company's inability to raise additional capital may cause it to reduce the level of its operations and would have a material adverse effect on its financial condition, ability to meet its obligations and operating needs and results of operations. As a result of potential liquidity problems, its auditors, Mann Frankfort Stein & Lipp CPAs, L.L.P. added an explanatory paragraph in their opinion on the Company's financial statements for the years ended December 31, 2001 and 2000, indicating that substantial doubt exists about its ability to continue as a going concern. See Note 2 of the Consolidated Financial Statements.

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FINANCIAL CONDITION: LIQUIDITY AND CAPITAL RESOURCES

The following table summarizes the Company's financial position for the periods indicated:

	December 31, (amounts in thousands)			
	2001		2000	
	Amount	%	Amount	%
Working Capital	$ --	--	$1,388	15
Property and equipment, net	5,980	85	5,345	58
Other noncurrent assets	1,043	15	2,476	27
Total	$7,023	100	$9,209	100
Working Capital	$1,197	17	$ --	--
Other non-current liabilities	--	--	550	6
Minority Interest	1,065	15	1,196	13
Stockholders' equity	4,761	68	7,463	81
Total	$7,023	100	$9,209	100

The change in the Company's financial position from December 31, 2000 to December 31, 2001, was primarily due to the sale of its' 50% interest in the Black Marlin Pipeline System for approximately $4.6 million, the installation of a platform to operate and maintain the Blue Dolphin Pipeline System for approximately $1.7 million net to the Company's interest, the sale to Fidelity Oil of its reversionary interest in proved properties acquired from American Resources of approximately $1.4 million and the impairment recorded for the Petroport and Sabine Seaport projects of approximately $1.9 million.

Historically, the Company has relied on the proceeds from financing activities and the sale of assets to supplement its capital requirements. In 2001, the Company financed its activities through the sale of assets and from revenue generated from its operating activities.

The Company's future cash flows are subject to a number of variables, including the level of gas and oil production, utilization of its pipeline systems, utilization of its services by third parties and commodity prices among others. The Company believes that it will have sufficient cash flow from operations, private equity or debt financing activities and the sale of assets to meet its obligations and operating needs for the year ending December 31, 2002. However, there can be no assurance that operations and other capital resources will provide cash in sufficient amounts to maintain planned levels of capital expenditures. The net cash provided by or used in operating, investing and financing activities is summarized below:

	Years Ended December 31 (amounts in thousands) 2001	2000
Net cash provided by (used in):		
Operating activities	$ 1,447	$ 3,691
Investing activities	2,412	(3,548)
Financing activities	(2,587)	762
Net increase in cash	$ 1,272	$ 905

The Company's cash flow from operating activities decreased by $2.2 million in 2001 from 2000, due primarily to lower revenues from oil and gas sales of approximately $.8 million and pipeline transportation of approximately $1.2 million, and higher general and administrative expenses of approximately $0.7 million.

Cash flow provided by investing activities during 2001 included the proceeds from the sale of the Company's interest in the Black Marlin Pipeline System of approximately $4.6 million and the sale of its reversionary interest to Fidelity Oil of proved properties that Fidelity Oil acquired from American Resources of approximately $1.4 million. Cash flow used in investing activities included the construction of a new offshore platform installed to operate and maintain the Blue Dolphin Pipeline of approximately $1.7 million, and exploration and development costs associated with oil and gas properties owned by American Resources of approximately $1.0 million.

Cash flow used in financing activities during the current period consisted primarily of the payment of convertible promissory notes and related party notes in the principal amount of approximately $2.2 million.

The Company previously announced a gas discovery in High Island Area Block A-7, in the Gulf of Mexico. The Company owns an 8.9% reversionary working interest in this field and it will begin to receive revenues from its reversionary interest after "payout" occurs. Payout is scheduled to occur after all of the other working interest owners have recovered their costs and expenses associated with developing the field from sales of gas and oil production from the field. In mid 2001, there were three wells producing in this field at a combined rate of approximately 60 Mmcf of natural gas per day. However, two of the three wells stopped producing and the remaining well is currently producing approximately 14 Mmcf of natural gas per day. Additionally, two unsuccessful exploratory wells were drilled in late 2001. The Company had expected to begin to receive revenues from its reversionary working interest in this field in late 2001, however, as a result of the above mentioned occurrences the Company does not expect to receive revenues until 2005.

In January 2001, the Company and its partners sold the Black Marlin Pipeline System for $7.3 million and the High Island Block A-5 pipeline for $2.0 million to Williams Field Services; $3.6 million and $1.0 million, respectively, net to the Company's interest. The Black Marlin System accounted for 1.0% and 30% of the Company's revenues for the years ended December 31, 2001 and 2000, respectively.

In November 2000, the Company elected to abandon the Buccaneer field due to adverse developments in the field. See Item 1 Business "Oil and Gas Exploration and Production Activities - Buccaneer Field." The Company reached an agreement with Tetra Applied Technologies, Inc. ("Tetra"), to plug and abandon the wells located in the Buccaneer Field which was completed in the first quarter of 2001 for approximately $1.4 million. In addition, Maritech Resources, Inc. ("Maritech") an affiliate of Tetra purchased an adjacent lease from Apache Corporation on which the Company provided production operating services. In December 2000, as a result of the Company's plans to abandon the Buccaneer Field platform facilities, the Company and Maritech terminated the operating agreement. The Company installed a new platform in 2001 at a cost of $1.7 million net to its interest, to operate and maintain the Blue Dolphin Pipeline System, as well as handle the production from Maritech's lease. The Blue Dolphin System was previously tied into and operated from the Buccaneer Field platforms.

In August 2001, the Company reached an agreement with Tetra to remove the Buccaneer Field platforms for a cost of approximately $2.6 million. See Item 1 Business "Oil and Gas Exploration and Production Activities - Buccaneer Field". Pursuant to the agreement, Tetra and the Company agreed to extended payment terms, whereby the Company will pay 20% upon completion and 5% per month

for twelve months, with the remaining balance due in the thirteenth month. To provide security for the extended payment terms, the Company provided Tetra with a first lien on its 50% interest in the Blue Dolphin Pipeline System. Operations to remove the platforms commenced in August 2001 and were suspended in December 2001, while the Company continues its discussions with the Texas Parks and Wildlife to leave the under water portion of the platforms in place as artificial reefs. The Company expects that the Texas Parks and Wildlife will make a decision as to whether the Company will be able to leave any of the Buccaneer Field platforms in place as artificial reefs, in the second quarter 2002. The Company requested and has received an extension from the MMS until October 1, 2002, to complete the removal and site clearance of the platform complexes. After the decision is made by the Texas Parks and Wildlife, Tetra will resume its removal operations. If a platform complex is left in place as an artificial reef, certain site clearance operations would be eliminated. The Company believes that its provision for abandonment costs of $4.6 million at December 31, 2001 is adequate.

The Company used $1.5 million of escrowed funds for abandonment costs in 2001 to pay for plugging and abandonment costs incurred. The Company expects to finance the remaining abandonment costs from working capital, the private placement of debt or equity securities, or the sale of assets.

In December 1999, the Company entered into an agreement with Fidelity Oil to manage their interest in the oil and gas properties acquired from American Resources for $40,000 per month. This amount was intended to reimburse the Company for the cost of the services provided. Fidelity Oil terminated this agreement effective January 31, 2001. During the years ended December 31, 2001 and 2000, the Company received $40,000 and $480,000, respectively, in management fees pursuant to this agreement.

In July 2000, the Company executed an agreement to provide transportation services for Vastar Resources in High Island Block A-5, offshore Texas in the Gulf of Mexico. To accommodate this production, the Company agreed to construct a 3.4 mile 12" diameter pipeline from the production platform in High Island A-5 to the Black Marlin Pipeline. The total cost to construct the pipeline was $1.9 million, $.9 million net to the Company's 50% interest in the pipeline. The pipeline was completed in September 2000. The Company sold this pipeline with the Black Marlin System in January 2001, as previously discussed.

In July 2000, the Company acquired an 83.3% ownership interest in an 8-inch, 12.78-mile pipeline from Walter Oil and Gas Corp. for approximately $224,000, net to its' interest. The pipeline extends from Galveston Area Block 350 to an interconnect to another pipeline in Galveston Area Block 391, approximately 14 miles south of the Company's Blue Dolphin Pipeline. The Company believes it is well positioned to attract production from future discoveries in the area.

The reserves and future net revenues presented in Item 1 "Business - Oil and Gas Exploration and Production Activities," reflect capital expenditures totaling $150,000, $328,000, $81,000, $111,000 and $225,000 in the years ending December 31, 2002, 2003, 2004, 2005 and 2006, respectively. Management will continue to evaluate its capital expenditure program based on, among other things, field reservoir performance, availability and cost of drilling and workover equipment, and demand and prices obtainable for the Company's production, as well as availability of capital resources. There can be no assurance that reserves will be developed as currently planned.

In April 2000, the Company amended its prospect generation program agreement with Fidelity Oil, whereby in exchange for certain participation rights of up to 100%, Fidelity Oil funded $1.1 million of the costs associated

with the program during 2000. Fidelity Oil also reimbursed the Company for seismic data acquired in connection with the prospect generation program. Fidelity Oil withdrew from the prospect generation program effective December 31, 2000. In 2001, the Company suspended its prospect generation program until it is able to obtain funding necessary to continue the program.

In December 1999, American Resources was paid approximately $4.5 million by Blue Dolphin Exploration for approximately 39.5 million shares of American Resources common stock, representing a 75% ownership interest, and $24.2 million by Fidelity Oil for an 80% interest in its' Gulf of Mexico assets. The proceeds were used by American Resources to retire certain indebtedness. The indebtedness included American Resources senior secured debt totaling approximately $51.2 million to Den norske bank ("Den norske"). Den norske sold the senior debt for $27.0 million and a contingent future payment if the cumulative net revenues received by American Resources and Fidelity Oil attributable to American Resources proved oil and gas reserves in the Gulf of Mexico as of January 1, 1999, exceed $30.0 million during the period January 1, 1999, through December 31, 2001, whereby Den norske will be entitled to receive an amount equal to 50% of the net revenues in excess of $30.0 million during that three-year period. The amount payable to Den norske will be paid 80% by Fidelity Oil and 20% by American Resources. A payment of approximately $.8 million was due on March 15, 2002, however, Den norske granted an extension of this payment until April 30, 2002. The Company has provided for a liability to Den norske in the amount of $.8 million at December 31, 2001.

In February 2002, the Company acquired a 1/3 interest in the Blue Dolphin Pipeline System and the inactive Omega Pipeline from MCNIC. Pursuant to the terms of the purchase and sales agreement, Blue Dolphin issued MCNIC a $750,000 promissory note due December 31, 2006, with required monthly payments to be made out of 90% of the net revenues of the interest acquired. The note bears interest at the rate of 6% per annum and is secured by the interest acquired. Additionally, contingent payments of up to $750,000 will be made, if the promissory note is retired before its maturity date, payable annually after the promissory note is retired until December 31, 2006, out of 50% of the net revenues from the interest acquired. The termination date, December 31, 2006, will be extended by one additional year, up to a maximum of two years, for years in which non-recurring, extraordinary expenditures, attributable to the interest acquired, exceeds $200,000, in the aggregate, during any year.

RESULTS OF OPERATIONS

For the year ended December 31, 2001, the Company reported a net loss of $2,649,142, compared to a net loss of $10,135,120 for the year ended December 31, 2000. The 2001 loss was primarily due to the impairment recorded for the Company's Petroport and Sabine Seaport projects of $1.9 million, and the 2000 loss was due to an impairment of oil and gas properties of $10.8 million.

2001 compared to 2000

Revenue from oil and gas sales. Revenues from oil and gas sales decreased by $824,938 in 2001, from those of 2000. The decrease was primarily due to an 18% reduction in production volumes due to normal production declines, resulting in a decrease in revenues of approximately $572,000. Oil and gas sales recorded in 2000 included revenues of approximately $286,000 from production from the Buccaneer Field prior to termination of production operations in July 2000.

Revenue from pipeline operations. Revenues from pipeline operations decreased by $1,220,473 or 55% in 2001 to $991,823. The decrease was due primarily to the sale of the Black Marlin Pipeline System in January 2001. The Black Marlin Pipeline System provided revenues of approximately $1.0 million for the previous period compared to approximately $50,000 for the current period. Additionally, revenues from pipeline operations decreased due to a decline in gas and oil volumes transported by the Blue Dolphin System, resulting in a decrease of revenues from this system of approximately $.2 million.

Operating Fees. The Company did not have current period revenues from operating fees due to the termination of its operating agreement with Maritech in December 2000.

Lease Operating Expenses. Lease operating expenses for 2001 decreased by $213,387 from 2000 due to the elimination of certain costs in 2001 associated with the Buccaneer Field of approximately $.3 million, offset in part by increased costs from the American Resources properties.

Pipeline operating expenses. Pipeline operating expenses in 2001 decreased by $459,945 or 47% from 2000. The decrease was primarily due to the sale of the Black Marlin Pipeline System in January 2001. Black Marlin Pipeline System operating expenses were approximately $.5 million for 2000 compared to approximately $33,000 for 2001.

Depletion, depreciation and amortization expense. Current period depletion, depreciation and amortization decreased $179,140 from the previous period. The decrease was primarily due to a $.1 million decrease in depreciation related to the Black Marlin Pipeline System that was sold in January 2001.

Impairment of assets. The Company recorded an impairment of its investment in the Petroport and Sabine Seaport projects of approximately $1.9 million, and increased the impairment of the Buccaneer Field by $1.0 million in 2001 due to revised plugging and abandonment estimates. In 2000, the Company recorded an impairment of oil and gas properties of $10.7 million, comprised of a non-cash write-off of proved reserves from the Buccaneer Field of $5.3 million and the recognition of associated plugging and abandonment costs estimated to be $5.4 million.

General and administrative expenses. General and administrative expenses for the current period increased $751,619 from the previous period. The increase was due in part to an increase in legal defense expenses of approximately $.2 million (See Item 3. "Legal Proceedings"), and the termination of the Management Services Agreement between the Company and Fidelity Oil, whereby the Company managed Fidelity Oil's interest in the oil and gas assets it acquired from American Resources in December 1999. Management fees of approximately $.5 million received from Fidelity Oil were recorded as a reduction to general and administrative expenses during the previous period.

Interest and other expense. Interest and other expense decreased $517,987 in the current period. In the current period, the Company increased the provision for the contingent payment to Den norske by $250,000, compared to the $550,000 recorded in 2000. In addition, the Company retired $2.2 million of promissory notes in January 2001, resulting in a decrease in interest expense from 2000 of approximately $129,000.

Gain on sale of assets. The Company recorded a gain on the sale of the Black Marlin Pipeline System of $1.4 million in January 2001.

Equity losses of affiliates. In the current period, the Company recorded losses from it's equity interest in Drillmar and New Avoca of $245,201.

Recently Issued Accounting Pronouncements

Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities" ("SFAS 133"), was issued in June 1998 by the Financial Accounting Standards Board. SFAS 133 establishes new accounting and reporting standards for derivative instruments and for hedging activities. This statement requires an entity to establish at the inception of a hedge, the method it will use for assessing the effectiveness of the hedging derivative and the measurement approach for determining the ineffective aspect of the hedge. Those methods must be consistent with the entity's approach to managing risk.

Certain provisions of SFAS 133 were amended by SFAS 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities - an amendment of Statement 133", SFAS 133, as amended, is effective for all fiscal quarters of fiscal years beginning after June 15, 2000. SFAS 133, as amended, did not have a material effect on the Company's consolidated financial position or the results of operations.

In July 2001, the FASB issued Statement No. 141 ("SFAS 141"), "Business Combinations," and Statement No. 142, "Goodwill and Other Intangible Assets" ("SFAS 142"). SFAS 141 requires that the purchase method of accounting be used for all business combinations initiated after June 30, 2001. SFAS 141 also specifies criteria intangible assets acquired in a purchase method business combination must meet to be recognized and reported apart from goodwill. SFAS 142 will require that goodwill and intangible assets with indefinite useful lives no longer be amortized, but instead tested for impairment at least annually in accordance with the provisions of SFAS 142. SFAS 142 will also require that intangible assets with definite useful lives be amortized over their respective estimated useful lives to their estimated residual values, and reviewed for impairment in accordance with SFAS 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of". The Company does not expect to have unamortized goodwill, unamortized identifiable assets, or unamortized negative goodwill upon adoption of SFAS 142 on January 1, 2002.

In August 2001, the FASB issued Statement No. 143 ("SFAS 143"), "Accounting for Asset Retirement Obligations," which addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. The standard applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or normal use of the asset.

SFAS 143 requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The fair value of the liability is added to the carrying amount of the associated asset and this additional carrying amount is depreciated over the life of the asset. If the obligation is settled for other than the carrying amount of the liability, the Company will recognize a gain or loss on settlement.

The Company is required and plans to adopt the provisions of SFAS 143 for the quarter ending March 31, 2003. To accomplish this, the Company must identify all legal obligations for asset retirement obligations and determine the fair value of these obligations on the date of adoption. The determination of fair value is complex and will require the Company to gather market information and develop cash flow models. Additionally, the Company will be required to develop processes to track and monitor these obligations. Because of the effort necessary to comply with the adoption of SFAS 143, it is not practicable for management to estimate the impact of adopting this Statement at the date of this report.

In October 2001, the FASB issued Statement No. 144 ("SFAS 144"), "Accounting for the Impairment or Disposal of Long-Lived Assets". SFAS 144 provides that long-lived assets to be disposed of by sale be measured at the lower of carrying amount or fair value less cost to sell, whether reported in continuing operations or in discontinued operations, and broadens the reporting of discontinued operations to include all components of an entity with operations that can be distinguished from the rest of the entity and that will be eliminated from the ongoing operations of the entity in a disposal transaction. SFAS 144 is effective for fiscal years beginning after December 15, 2001.

The Company is currently assessing the impact of SFAS 144 on its financial condition and results of operations.

Item 7. Financial Statements and Supplementary Data

Index to Financial Statements:

Independent Auditors' Report

The Board of Directors
Blue Dolphin Energy Company

We have audited the accompanying consolidated balance sheet of Blue Dolphin Energy Company and subsidiaries as of December 31, 2001, and the related consolidated statements of operations, stockholders' equity and cash flows for each of the years in the two-year period ended December 31, 2001. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Blue Dolphin Energy Company and subsidiaries as of December 31, 2001, and the results of their operations and their cash flows for each of the years in the two-year period ended December 31, 2001 in conformity with accounting principles generally accepted in the United States.

The accompanying consolidated financial statements have been prepared assuming that the Company will continue as a going concern. As shown in the consolidated financial statements, the Company has a working capital deficiency, has incurred net losses in recent years, and has a significant accumulated deficit. Those conditions raise substantial doubt about the Company's ability to continue as a going concern. Management's plans in regard to those matters are described in Note 2. The consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty.

/s/ Mann Frankfort Stein & Lipp CPAs, LLP

Houston, Texas
March 18, 2002

BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES

Consolidated Balance Sheet

December 31, 2001

Assets

Current assets:	
Cash and cash equivalents	$ 3,343,560
Trade accounts receivable	1,123,905
Accounts receivable - related party	134,334
Prepaid expenses and other assets	163,825
Total current assets	4,765,624
Property and equipment, at cost:	
Oil and gas properties, including $221,832 of unproved leasehold cost (full-cost method)	27,570,342
Onshore separation and handling facilities	1,583,428
Land	850,000
Pipelines	2,920,135
Other property and equipment	283,192
	33,207,097
Less accumulated depletion, depreciation, amortization and impairment	27,227,024
	5,980,073
Deferred federal income tax	244,444
Other assets	798,871
	$ 11,789,012

See accompanying notes to consolidated financial statements.

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BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES

Consolidated Balance Sheet, continued

December 31, 2001

Liabilities and Stockholders' Equity

Current liabilities:	
Trade accounts payable	$ 1,039,820
Accrued expenses and other liabilities	4,923,085

Total current liabilities	5,962,905
Minority interest	1,064,991
Stockholders' equity:	
Common stock, $.01 par value, 10,000,000 shares authorized and 6,091,449 shares issued and outstanding	60,915
Additional paid-in capital	25,722,060
Accumulated (deficit)	(21,021,859)
Total stockholders' equity	4,761,116
	$ 11,789,012

See accompanying notes to consolidated financial statements.

BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES

Consolidated Statements of Operations

Years ended December 31, 2001 and 2000

	2001	2000
Revenue from operations:		
Oil and gas sales	$ 4,694,202	5,519,140
Pipeline operations	991,823	2,212,296
Operating fees	--	210,534
Revenue from operations	5,686,025	7,941,970
Cost of operations:		
Lease operating expenses	1,155,549	1,368,936
Pipeline operating expenses	517,054	976,999
Depletion, depreciation and amortization	1,817,770	1,996,910
Impairment of assets	2,940,464	10,754,976
General and administrative expenses	2,845,459	2,093,840
Cost of operations	9,276,296	17,191,661
Loss from operations	(3,590,271)	(9,249,691)
Other income (expense):		
Interest and other expense	(243,591)	(761,578)
Gain on sale of assets	1,417,626	--

Interest and other income	116,417	114,107
Equity in losses of affiliates	(245,201)	--
Loss before minority interest and income taxes	(2,545,020)	(9,897,162)
Minority interest	(104,122)	(237,958)
Income tax expense	--	--
Net loss	$(2,649,142)	(10,135,120)
Loss per common share-basic and diluted	$ (0.44)	(1.70)
Weighted average number of common shares outstanding - basic and diluted	6,004,019	5,963,318

See accompanying notes to consolidated financial statements.

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BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES

Consolidated Statements of Stockholders' Equity

Years ended December 31, 2001 and 2000

	Common stock	Additional paid-in capital	Accumulated (deficit)	stoc e
Balance at December 31, 1999	$ 59,509	25,823,817	(8,237,597)	1
Exercise of 33,665 stock options	336	109,843	--	
Issuance of shares to 401K plan	300	89,700	--	
Stock registration costs and other	22	(247,943)	--	
Net loss			(10,135,120)	(1
Balance at December 31, 2000	60,167	25,775,417	(18,372,717)	
Exercise of 3,333 stock options	33	12,715	--	
Issuance of shares to 401K plan	500	79,500	--	

Stock registration costs and other	215	(145,572)	--	
Net loss			(2,649,142)	(
Balance at December 31, 2001	$ 60,915	25,722,060	(21,021,859)	

See accompanying notes to consolidated financial statements.

BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES

Consolidated Statements of Cash Flows

Years ended December 31, 2001 and 2000

	2001	2000
Operating activities:		
Net loss	$(2,649,142)	(10,135,120)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depletion, depreciation and amortization	1,817,770	1,996,910
Minority interest	104,122	237,958
Gain on sale of property and equipment	(1,417,626)	--
Impairment of assets	2,940,464	10,754,976
Increase in other liabilities	250,000	550,000
Equity in losses of affiliates	245,201	--
Issuance of shares to 401K plan	80,000	90,000
Changes in operating assets and liabilities:		
Trade accounts receivable	1,148,512	(864,423)
Prepaid expenses and other assets	(35,912)	190,226
Abandonment costs incurred	(442,984)	--
Other assets	28,389	--
Trade accounts payable, accrued expenses and other liabilities	(622,292)	870,276
Net cash provided by operating activities	1,446,502	3,690,803

Investing activities:		
Exploration and development costs	(1,022,843)	(1,620,564)
Purchases of property and equipment	(1,764,245)	(1,269,924)
Net proceeds from sale of assets	5,985,000	--
Development costs - Petroport	(59,305)	(155,576)
Development costs - New Avoca	(234,140)	(184,248)
Acquisition and development costs - Drillmar	(492,460)	--
Funds escrowed for abandonment costs	--	(317,164)
Net cash provided by (used in) investing activities	2,412,007	(3,547,476)

See accompanying notes to consolidated financial statements.

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BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES

Consolidated Statements of Cash Flows, Continued

Years ended December 31, 2001 and 2000

	2001	2000
Financing activities:		
Proceeds from borrowings, related party	--	1,000,000
Payments on borrowings, preferred stockholders	(218,412)	(100,633)
Payments on borrowings, related parties	(2,000,000)	--
Payments of offering costs and other	(145,357)	(247,921)
Dividends paid by subsidiary	(235,610)	--
Net proceeds from the exercise of stock options	12,748	110,179
Net cash provided by (used in) financing activities	(2,586,631)	761,625
Increase in cash and cash equivalents	1,271,878	904,952
Cash and cash equivalents at beginning of year	2,071,682	1,166,730
Cash and cash equivalents at end of year	$ 3,343,560	2,071,682

Supplementary cash flow information:		
Interest paid	$ 98,500	86,316
	===========	===========
Taxes paid	$ 6,530	8,498
	===========	===========

See accompanying notes to consolidated financial statements.

BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES

Notes to Consolidated Financial Statements

December 31, 2001 and 2000

(1) Organization and Significant Accounting Policies

Organization

Blue Dolphin Energy Company (the "Company") was incorporated in Delaware in January 1986 to engage in oil and gas exploration, production and acquisition activities and oil and gas transportation and marketing. It was formed pursuant to a reorganization effective June 9, 1986.

Principles of Consolidation

The consolidated financial statements of the Company include the accounts of its wholly-owned subsidiaries and majority owned subsidiary (American Resources). All significant intercompany balances and transactions have been eliminated in consolidation.

Accounting Estimates

Management has made a number of estimates and assumptions relating to the reporting of assets and liabilities and to the disclosure of contingent assets and liabilities including reserve information which affects the depletion calculation as well as the computation of the full cost ceiling limitation to prepare these financial statements in conformity with accounting principles generally accepted in the United States. Actual results could differ from those estimates.

Cash Equivalents

Cash equivalents include liquid investments with an original maturity of three months or less. Cash balances are maintained in depository and overnight investment accounts with a financial institution which at times, exceed insured limits. The Company monitors the financial condition of the financial institution and has experienced no losses associated with these accounts.

Oil and Gas Properties

Oil and gas properties are accounted for using the full-cost method of accounting, whereby all costs associated with acquisition, exploration, and development of oil and gas properties, including directly related internal costs, are capitalized on a country-by-country cost center basis. Due to the difference in the expected life of the reserves of

the properties, the Company used two separate cost centers, one for its Buccaneer Field property and one for its other properties. With the write off of the Buccaneer Field during the year ended December 31, 2000, the Company is now utilizing one cost center for all of its properties. Amortization of such costs and estimated future development costs are determined using the unit-of-production method. Provision for the estimated costs of offshore platform and well abandonment, net of salvage value, is computed on the units of production method and is included in depletion, depreciation and amortization. Costs directly associated with the acquisition and evaluation of unproved properties are excluded from the amortization computation until it is determined whether or not proved reserves can be assigned to the properties or impairment has occurred. Estimated proved oil and gas reserves are based upon reports of independent petroleum engineers. The net carrying value of oil and gas properties, less related deferred income taxes, is limited to the lower of unamortized cost or the cost center ceiling, defined as the sum of the present value (10% discount rate applied) of estimated future net revenues from proved reserves, after giving effect to income taxes, and the lower of cost or estimated fair value of unproved properties. Disposition of oil and gas properties are recorded as adjustments to capitalized costs, with no gain or loss recognized unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves.

The following table reflects the depletion expense incurred from oil and gas properties during the periods indicated:

	Year Ended December 31, 2001	2000
Depletion expense per Mcf equivalent produced	$1.53	$1.18

At December 31, 2001, oil and gas properties included $221,832 of unproved leasehold costs that are not being amortized. These costs will begin to be amortized when they are evaluated and proved reserves are discovered, impairment is indicated or when the lease term expires. Unproved leasehold costs consist of interests in state and federal leases located in the Gulf of Mexico with expiration dates ranging from July 2002 to November 2004. In order to retain the leases after the primary term, they must be producing or development operations must be in progress. The leases have primary terms of 5 years. Development of these leases is dependent upon the other owners of the leases to initiate a plan of development.

The following table reflects the periods when costs were incurred for unproved leasehold costs:

BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES

Notes to Consolidated Financial Statements

		December 31,		
	Total	2001	2000	Prior Years
Property acquisition costs	$ 177,518	(102,920)	--	280,438
Exploration costs	44,314	(106,030)	--	150,344
	$ 221,832	(208,950)	--	430,782

The Company capitalizes interest on expenditures made in connection with significant exploration and production projects that are not subject to current amortization. Interest is capitalized only for the period that activities are in progress to bring these projects to their intended use. No interest has been capitalized for the periods reflected herein.

Pipelines and Facilities

Pipelines and facilities are recorded at cost. Depreciation is computed using the straight-line method over estimated useful lives of 10-22 years. Provision for the estimated cost of pipeline and facilities abandonment, net of salvage value, is computed on a straight line basis over the estimated useful life of such assets and is included in Depletion, Depreciation and Amortization.

Other Property and Equipment

Depreciation of furniture, fixtures and other equipment, including assets held under capital leases, is computed using the straight-line method over estimated useful lives of 3-10 years.

In accordance with Statement of Financial Accounting Standards ("SFAS") No. 121, Accounting for the Impairment of Long-lived Assets and for Long-lived Assets to Be Disposed Of, assets are grouped and evaluated for impairment based on the ability to identify separate cash flows generated therefrom. For the year ended December 31, 2001, the Company recorded a full impairment of $1.9 million of its investment in both the Petroport and Sabine Seaport projects.

Abandonment

A provision for the abandonment, dismantlement and site clearance of offshore production platforms and existing wells is made using the unit-of-production method applied to estimates based on current costs. A provision for pipeline and pipeline facilities abandonment costs is also provided using the straight-line method over the estimated useful lives of the pipeline and pipeline facilities. Until such time that the liability becomes current, the provisions are included in accumulated depletion, depreciation, amortization and impairment, and are undiscounted. Aggregate abandonment liability is estimated to be approximately $4,866,000 at December 31, 2001, of which $1,556,000 is included in accumulated depletion, depreciation, amortization, and impairment and $3,300,000 is included in accrued expenses and other liabilities.

New Avoca and Drillmar

The Company records its investment in New Avoca (25% owned and managed by the Company) and Drillmar using the equity method of accounting. Under the equity method, investments are recorded at cost plus the Company's equity in undistributed earnings and losses after acquisition.

Stock-Based Compensation

The Company applies SFAS No. 123, Accounting for Stock-Based Compensation, which allows a company to adopt a fair value based method of accounting for a stock-based employee compensation plan or to continue to use the intrinsic value based method of accounting prescribed by Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees. The Company chose to continue to account for stock-based compensation under the intrinsic value method and provides the pro forma effects of the fair value method as required.

Recognition of Oil and Gas Revenue

Sales from producing wells are recognized on the entitlement method of accounting which defers recognition of sales when, and to the extent that, deliveries to customers exceed the Company's net revenue interest in production. Similarly, when deliveries are below the Company's net revenue interest in production, sales are recorded to reflect the full net revenue interest. The Company's imbalance liability at December 31, 2001 and 2000 was not material.

Recognition of Pipeline Transportation Revenue

Revenue from the transportation of gas, condensate and crude oil is recognized on the accrual basis as products are transported.

Operation of Oil and Gas Properties

Until December 2000, the Company operated, for a monthly fee, oil and gas properties in which it did not own an interest. Revenues and costs from these activities are included in operating fees and lease operating expenses, respectively. Operating fees received related to properties in which the Company owns an interest are netted against the appropriate operating costs in the statement of operations. Fees received in excess of costs incurred are reflected as a reduction of the full cost pool.

Income Taxes

The Company provides for income taxes using the asset and liability method pursuant to SFAS No. 109, Accounting for Income Taxes ("Statement 109"). Under the asset and liability method of Statement 109, deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and operating loss and tax credit carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date.

Earnings Per Share

The Company follows SFAS No. 128 ("Statement 128"), "Earnings per Share", for computing and presenting earnings per share and requires, among other things, dual presentation of basic and diluted earnings per share on the face of the statement of operations.

The employee stock options at December 31, 2001 and 2000, were not included in the computation of diluted earnings per share because the effect of their assumed exercise and conversion would have an antidilutive effect on the computation of diluted loss per share.

Environmental

The Company is subject to extensive Federal, state and local environmental laws and regulations. These laws, which are constantly changing, regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites. Environmental expenditures are expensed or capitalized depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefits are expensed. Liabilities for expenditures of a noncapital nature are recorded when environmental assessment and/or remediation is probable, and the costs can be reasonably estimated. Such liabilities are generally recorded at their undiscounted amounts unless the amount and timing of payments is fixed or reliably determinable.

BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES

Notes to Consolidated Financial Statements

Recently Issued Accounting Pronouncements

Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities" ("SFAS 133"), was issued in June 1998 by the Financial Accounting Standards Board. SFAS 133 establishes new accounting and reporting standards for derivative instruments and for hedging activities. This statement requires an entity to establish at the inception of a hedge, the method it will use for assessing the effectiveness of the hedging derivative and the measurement approach for determining the ineffective aspect of the hedge. Those methods must be consistent with the entity's approach to managing risk. Certain provisions of SFAS 133 were amended by SFAS 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities - an amendment of Statement 133", SFAS 133, as amended, is effective for all fiscal quarters of fiscal years beginning after June 15, 2000. SFAS 133, as amended, did not have a material effect on the Company's consolidated financial position or the results of operations.

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In August 2001, the FASB issued Statement No. 143 ("SFAS 143"), "Accounting for Asset Retirement Obligations," which addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. The standard applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or normal use of the asset.

SFAS 143 requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The fair value of the liability is added to the carrying amount of the associated asset and this additional carrying amount is depreciated over the life of the asset. If the obligation is settled for other than the carrying amount of the liability, the Company will recognize a gain or loss on settlement.

BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES

Notes to Consolidated Financial Statements

The Company is required and plans to adopt the provisions of SFAS 143 for the quarter ending March 31, 2003. To accomplish this, the Company must identify all legal obligations for asset retirement obligations and determine the fair value of these obligations on the date of adoption. The determination of fair value is complex and will require the Company to gather market information and develop cash flow models. Additionally, the Company will be required to develop processes to track and monitor these obligations. Because of the effort necessary to comply with the adoption of SFAS 143, it is not practicable for management to estimate the impact of adopting this Statement at the date of this report.

In October 2001, the FASB issued Statement No. 144 ("SFAS 144"), "Accounting for the Impairment or Disposal of Long-Lived Assets". SFAS 144 provides that long-lived assets to be disposed of by sale be measured at the lower of carrying amount or fair value less cost to sell, whether reported in continuing operations or in discontinued operations, and broadens the reporting of discontinued operations to include all components of an entity with operations that can be distinguished from the rest of the entity and that will be eliminated from the ongoing operations of the entity in a disposal transaction. SFAS 144 is effective for fiscal years beginning after December 15, 2001.

The Company is currently assessing the impact of SFAS 144 on its financial condition and results of operations.

Reclassifications

Certain 2000 balances have been reclassified to conform with the 2001 financial statement presentation. There is no effect on net loss due to the reclassifications.

(2) Liquidity and Going Concern

At December 31, 2001 the Company's working capital deficit was approximately $1.2 million. In order to satisfy its working capital and capital expenditure requirements in 2002, the Company believes that it will need to raise between $2.0 to $3.0 million of capital. The Company will need to seek external financing and/or sell assets to raise the necessary capital. There can be no assurance that the Company will be able to obtain financing or sell assets on commercially reasonable terms. The Company's inability to raise capital may have a material adverse effect on its financial condition, ability to meet its obligations and operating needs and results of operations. The consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty.

BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES

Notes to Consolidated Financial Statements

(3) Fair Value of Financial Instruments

The carrying values of cash and cash equivalents, receivables and accounts payable approximate fair value due to the short-term maturities of these instruments.

(4) Income Taxes

Income tax expense for both 2001 and 2000 was $0.

The income tax effects of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities at December 31, 2001 are presented below:

Deferred tax assets:	
Net operating loss carryforwards	$ 10,739,000
Alternative minimum tax credit	244,444
Basis differences in property and equipment	1,524,000
Total gross deferred tax assets	12,507,444
Deferred tax liabilities-state tax	(34,000)
Net deferred tax asset	12,473,444
Less valuation allowance	(12,229,000)
Deferred tax asset	$ 244,444

In 1999, the Company acquired a 75% interest in American Resources, which had deferred tax assets of approximately $8.5 million made up of basis differences in oil and gas properties and net operating losses. A full valuation allowance was recorded to reduce the corresponding deferred assets, since it is more likely than not that they will not be realized, due to the limitation of the use of the net operating loss carryforwards resulting from the ownership change in December 1999.

In assessing the realizability of deferred tax assets, the Company applies SFAS No. 109 to determine whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. As a result, the Company's valuation allowance at December 31, 2001 reduces the deferred tax assets to $244,444.

The Company's effective tax rate applicable to continuing operations in 2001 and 2000 is as follows:

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	2001	2000
Expected tax rate	(34%)	(34%)
State taxes, net of federal benefit	--	--
Expenses not deductible for tax purposes	--	--
Increase in valuation allowance recognized in earnings	34%	34%
Other	--	--
	0%	0%

For federal tax purposes, the company had a net operating loss carryforward ("NOL") of approximately $31.6 million and $28.3 million for the years ended December 31, 2001 and 2000, respectively. These NOLs must be utilized prior to their expiration, which is between 2002 and 2021. Of the $31.6 million of NOLs as of December 31, 2001, $17.5 million relate to American Resources.

The Company has an alternative minimum tax credit carry forward of $244,444 that does not expire and may be applied to reduce regular tax to an amount not less than the alternative minimum tax payable in any one year.

(5) Long-term Debt

The Company retired $218,412 principal amount of promissory notes in January 2001. The promissory notes were originally issued in December 1996, to holders of the Company's Preferred Stock as full payment of the cumulative preferred stock dividends. The promissory notes were unsecured and bore interest at the rate of 10.25% per annum. Interest only was payable semi-annually with the principal due on December 31, 2000.

In December 1999, the Company issued a $1.0 million unsecured convertible promissory note to Harris A. Kaffie, a director of the Company. This convertible promissory note originally due June 1, 2000 was extended to March 31, 2001, bore interest at 10% per annum, and was convertible into Common Stock at $6.00 per share. This convertible promissory note and accrued interest of $64,361 were paid in January 2001.

The Company issued three unsecured convertible promissory notes in 2000 totaling $1.0 million; two in the principal amount of $200,000 each on May 25, 2000 and July 6, 2000, issued to Ivar Siem, Chairman of the Company, and one in the principal amount of $600,000 on November 30, 2000, issued to TI A/S, beneficially controlled by Ivar Siem. The convertible promissory notes were due March 31, 2001, bore interest at the rate of 10% per annum and were convertible into Common Stock at the rate of $6.00 per share. These convertible promissory notes and accrued interest of $32,790 were paid in January 2001.

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(6) Stockholders' Equity

In 2001, the Company incurred costs totaling $185,943 associated with the registration of shares of its Common Stock. In addition, the Company issued 17,867 shares of its Common Stock as a severance payment to a former employee and recorded compensation expense of $28,586. The Company also issued 2,824 shares to the board of directors and recorded an expense of $12,000. In 2000, the Company incurred costs totaling $263,458 associated with the registration of shares of Common Stock, $.01 par value per share. In addition, the Company issued 2,785 shares of its Common Stock as a severance payment to a former employee and recorded compensation expense of $15,537.

(7) Stock Options

Effective April 14, 2000, the Company adopted, after approval by stockholders, a stock incentive plan (the "2000 Plan"). The stock subject to the options and other provisions of the 2000 Plan are shares of the Company's Common Stock $.01 par value (the "Stock"). No more than 500,000 shares of Stock will be available for incentive stock options ("ISOs"). The 2000 Plan is administered by the Compensation Committee of the Board of Directors. Options granted must be exercised within 10 years from their grant date. The exercise price of ISOs cannot be less than 100% of the fair market value of a share of Stock. The 2000 Plan also provides for the granting of other incentive awards, however only ISOs and non-statutory stock options have been issued under the 2000 Plan.

The Company adopted a stock option plan in 1996 (the "1996 Plan"). The stock subject to the options and other provisions of the 1996 Plan are shares of the Company's Common Stock. The total amount of the Common Stock with respect to which options may be granted shall not exceed in the aggregate 10% of the number of issued and outstanding shares of Common Stock of the Company. The stock options become exercisable from time to time in part or as a whole, as the Compensation Committee, appointed by the Board of Directors, or the Board of Directors in their discretion may provide. However, the Committee shall not grant options which may become exercisable in any one calendar year to purchase more than one-third of the maximum amount granted. All options expire five years after the date of grant. The price of options granted may not be less than eighty-five percent of the fair market value of the Common Stock on the date the option is granted. Optionees must continue their association with the Company for six months after exercising the options, or the underlying stock reverts to the Company.

At December 31, 2001 the Company has reserved a total of 153,173 shares of Common Stock for issuance under the above mentioned stock option plans. The outstanding stock options granted to key employees, officers and directors, for the purchase of shares of the Company's Common Stock, are as follows:

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		Exercise price per share	
	Shares	From	To
Balance, December 31, 1999	177,104	2.789	5.000
Granted	55,300	6.000	6.000
Expired	(47,503)	2.789	6.000
Exercised	(33,665)	2.789	3.984
Balance, December 31, 2000	151,236	2.789	6.000
Granted	42,104	1.900	1.900
Expired	(36,834)	3.125	6.000
Exercised	(3,333)	3.825	3.825
Balance, December 31, 2001	153,173	1.900	6.000

The weighted average exercise price per share was $3.825 and $3.365 in 2001 and 2000, respectively.

As of December 31, 2001, options for 122,506 shares of Common Stock were immediately exercisable. There where 42,104 and 55,300 options granted in 2001 and 2000, respectively. Pursuant to the requirements of FASB No. 123, the weighted average fair market value of options granted during 2001 and 2000 was $0.24 per share and $1.30 per share, respectively. The weighted average closing bid prices for the Company's stock at the date the options were granted during 2001 and 2000 are $1.90 per share and $5.25 per share, respectively. The fair market value pursuant to FASB No. 123 of each option granted is estimated on the date of grant using the Black-Scholes options-pricing model. The model assumed expected volatility of 29% and 70%, risk-free interest rate of 2.22% and 6.39% for grants in 2001 and 2000, respectively, and an expected life of 1 year. As the Company has not declared dividends on its Common Stock since it became a public entity, no dividend yield was used. Actual value realized, if any, is dependent on the future performance of the Company's Common Stock and overall stock market conditions. There is no assurance the value realized by an optionee will be at or near the value estimated by the Black-Scholes model.

No compensation expense was recorded in 2001 and 2000 for stock options granted. Had compensation cost for the Company's stock option plans been determined based on the fair market value at the grant dates for awards made, the Company's net loss and loss per share would have been adjusted to the pro forma amounts indicated below:

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	Year ended December 31, 2001	2000
Net (loss) as reported	$ (2,649,142)	$ (10,135,120)
Pro Forma	$ (2,759,436)	$ (10,271,293)
Basic and diluted (loss)		
Per share as reported	(0.44)	(1.70)
Pro Forma	(0.46)	1.72)

Outstanding options at December 31, 2001 expire between December 25, 2002 and December 17, 2011.

(8) Related Party Transactions

Related party transactions which are not disclosed elsewhere in these consolidated financial statements are discussed in the following paragraphs:

In September 2001, Drillmar, a 12.8% owned affiliate of the Company, entered into a merger agreement and merged with Zephyr Drilling Ltd. ("Zephyr"). Prior to the merger, Zephyr was a limited partnership in which Drillmar was the general partner. Zephyr owned a semi-submersible drilling rig that has been prepared for reconfiguration into a semi-tender. As a result of the merger, the Company's interest in Drillmar decreased from 64% to 12.8%.

Ivar Siem, Chairman of the Company, and Harris A. Kaffie, a Director of the Company, were limited partners of Zephyr. After the merger between Drillmar and Zephyr, Messers. Siem and Kaffie were owners of 30.3% and 30.6%, respectively, of Drillmar's common stock. During 2001, Messrs. Siem and Kaffie provided funding to Drillmar of $525,000 and $425,000, respectively, and were issued unsecured promissory notes from Drillmar. The promissory notes are due June 30, 2002 and bear interest at the rate of 10% per annum. Along with the promissory notes, Drillmar issued detachable warrants to Messrs. Siem and Kaffie of 52,500 and 42,500, respectively. Each warrant provides for the purchase of one share of Drillmar common stock at $5 per share and are exercisable through January 31, 2005. The promissory notes issued by Drillmar are nonrecourse to the Company.

In January 2001, the Company entered into an agreement with Drillmar whereby it agreed to provide office space and certain management and administrative services to Drillmar for approximately $40,000 per month. This agreement can be terminated at any time by the mutual agreement of the parties. Through October 2001, the Company used the monthly payments it was entitled to receive to fund its investment in Drillmar.

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(9) Leases

The Company has various noncancelable operating leases which continue through 2006. The following is a schedule of future minimum lease payments required under noncancelable operating leases at December 31, 2001:

Year ending December 31,	
2002	$ 186,498
2003	185,521
2004	195,617
2005	195,617
2006	195,617
	$ 958,870

Rental expense under operating leases for the years indicated are as follows:

Year ended December 31,	
2001	$ 198,548
2000	190,211

(10) Commitments and Contingencies

As a result of the decision to cease operating activities in the Buccaneer Field, the Company's leases in or on the Buccaneer Field terminated in January 2001. The Company must plug and abandon all remaining wells and remove platform facilities within one year from the termination of the leases. In 2001, the Company plugged its remaining wells at a cost of approximately $1.4 million. During the operations of removing the Buccaneer Field platform complexes in 2001 at a cost of approximately $0.4 million, discussions were initiated with the Texas Parks and Wildlife ("TP&W") in an effort to leave certain of the under water portions of the platform complexes in place as artificial reefs. In December 2001, operations to remove the platform complexes were suspended while the Company continues its discussions with the TP&W.

The Company expects that the TP&W will make a decision to leave either one, both or neither of the Buccaneer Field platform complexes in place as artificial reefs in the second quarter 2002. If one or both of the platform complexes are left in place as an artificial reef, certain site clearance costs would be eliminated. The Company requested and has received an extension from the MMS until October 1, 2002 to complete the removal and site clearance of the platform complexes. The Company still believes that its provision for abandonment costs of $4.6 million at December 31, 2001 is adequate.

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In December 1999, American Resources received approximately $4.5 million from Blue Dolphin Exploration for American Resources common stock representing a 75% ownership interest and $24.2 million from Fidelity Oil for an 80% interest in its Gulf of Mexico assets. American Resources senior secured debt was held by Den norske bank ("Den norske"). Den norske sold the senior debt to the Company for the right to receive a possible future payment if the cumulative net revenues received by American Resources and Fidelity Oil attributable to American Resources proved oil and gas reserves in the Gulf of Mexico as of January 1, 1999, exceed $30.0 million during the period January 1, 1999, through December 31, 2001, whereby Den norske will be entitled to receive an amount equal to 50% of those net revenues in excess of $30.0 million during that three-year period. The amount payable to Den norske will be paid 80% by Fidelity Oil and 20% by American Resources. A payment of approximately $.8 million was due on March 15, 2002; however, Den norske granted an extension of this payment until April 30, 2002. The Company has provided for a liability to Den norske in the amount of $.8 million at December 31, 2001.

On May 8, 2000, American Resources and its former Chief Financial Officer, were named in a lawsuit in the United States District Court for the Southern District of Texas, Houston Division, styled H&N Gas, Limited Partnership, et al. v. Richard Hale, et al (Case No H-00-1371). The lawsuit alleges, among other things, that H&N Gas ("H&N") was defrauded by American Resources in connection with gas purchase options and gas price swap contracts entered into from February 1998 through September 1999. H&N alleges unlawful collusion between American Resources' prior management and the then president of H&N, Richard Hale ("Hale"), to the detriment of H&N. H&N generally alleges that Hale directed H&N to purchase illusory options from American Resources that bore no relation to any physical gas business and that American Resources did not have the financial resources and/or sufficient quantity of gas to perform. H&N further alleges that American Resources and Hale colluded with respect to swap transactions that were designed to benefit American Resources at the expense of H&N. H&N further alleges civil conspiracy against all the defendants. H&N is seeking approximately $6.2 million in actual damages plus treble damages, punitive damages and prejudgment interest against American Resources directly. As a result of its conspiracy allegation, H&N also contends that all defendants are jointly and severally liable for over $40.0 million in actual damages plus treble damages, punitive damages and prejudgment interest. American Resources intends to vigorously defend this claim.

The Company is involved in various other claims and legal actions arising in the ordinary course of business. In the opinion of management, the ultimate disposition of these matters will not have a material effect on the Company's financial position, results of operations or cash flows.

(11) Business Segment Information

The Company's income producing operations are conducted in two principal business segments: oil and gas exploration and production, which includes upstream projects, and pipeline operations, which includes mid-stream projects. Intersegment revenues consist of transportation, general processing and storage fees charged by certain

BLUE DOLPHIN ENERGY COMPANY AND SUBSIDIARIES

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subsidiaries to another for gas and crude oil transported through the Blue Dolphin Pipeline System. The intercompany revenues and expenses are eliminated in consolidation. Information concerning these segments for the years ended December 31, 2001and 2000 is as follows:

	Revenues	Intersegment revenues	Operating income (loss)(1)	Identifia asset
Year ended December 31, 2001:				
Oil and gas exploration and production and operating fees	$ 4,694,202		(616,124)	5,125,
Pipeline operations	991,823		(11,756)	4,433,
Other	--		(3,189,867)	2,230,
Consolidated	5,686,025		(3,817,747)	11,789,
Other income			1,272,727	
Loss before income taxes			(2,545,020)	
Year ended December 31, 2000:				
Oil and gas exploration and production and operating fees	$ 5,735,674	6,000	(8,577,943)	4,164,
Pipeline operations	2,225,312	13,016	625,486	8,958,
Other	(19,016)		(1,297,234)	789,
Consolidated	7,941,970		(9,249,691)	13,912,
Other expense			(647,471)	
Loss before income taxes			(9,897,162)	

1. Consolidated income (loss) from operations includes $1,223,117 and $1,188,721 in unallocated general and administrative expenses, and unallocated depletion, depreciation and amortization of $1,966,750 and $89,488 for the years ended December 31, 2001 and 2000, respectively.

2. Pipeline depletion, depreciation and amortization includes a provision

for pipeline abandonment of $19,740 for the years ended December 31, 2001 and 2000, respectively. Oil and gas depletion, depreciation and amortization includes a provision for abandonment costs of platforms and wells of $13,793 for the year ended December 31, 2001. In addition, the Company recorded an expense of approximately $1.0 million for the year ended December 31, 2001, as a result of a change in the estimated costs associated with the Buccaneer Field abandonment.

3. See the supplemental disclosures for oil and gas producing activities for discussion of capitalized costs incurred for oil and gas production operations. Capital expenditures of $1,737,331 were incurred for pipeline operations for the year ended December 31, 2001. Capitalized expenditures of $59,305 were incurred for mid-stream projects for the year ended December 31, 2001.

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The Company's primary market area is the Texas and Louisiana Gulf Coast region of the United States. The Company has a concentration of credit risk with customers in the energy and petrochemical industries. The Company's customers may be similarly affected by changes in economic, regulatory or other factors. Trade receivables are generally not collateralized; however, the Company's customers' historical and future credit positions are thoroughly analyzed prior to extending credit. In 2000, no customer accounted for more than 10% of the Company's total revenues. Revenues from major customers exceeding 10% of segment revenues were as follows for the period indicated.

	Oil and gas sales and operating fees	Pipeline operations	Total
Year Ended December 31, 2001:			
Houston Exploration	$ --	639,975	639,975

(12) Supplemental Oil and Gas Information - Unaudited

The following supplemental information regarding the oil and gas activities of the Company is presented pursuant to the disclosure requirements promulgated by the Securities and Exchange Commission ("SEC") and SFAS No. 69, Disclosures About Oil and Gas Producing Activities (`Statement 69").

In November 2000, the Company decided to abandon the Buccaneer Field as a result of the occurrence of unforeseen adverse events. As a result of this decision, the leases on the field terminated in January 2001 pursuant to their terms.

The timing and amount of estimated future development costs may significantly increase or decrease the Company's total proved and proved developed reserve volumes, the Standardized Measure of Discounted Future Net Cash Flows, and the components and changes therein. These reserves and future net revenues reflect capital expenditures totaling $150,000, $328,000, $81,000, $111,000 and $225,000 in the years ending December 31, 2002, 2003, 2004, 2005 and 2006, respectively.

Estimated Quantities of Proved Oil and Gas Reserves

Set forth below is a summary of the changes in the estimated quantities of the Company's crude oil and condensate, and gas reserves for the periods indicated, as estimated by Ryder Scott Company as of December 31, 2001. All of the Company's reserves are located within the United States. Proved reserves cannot be measured exactly because the estimation of reserves involves numerous judgmental determinations. Accordingly, reserve estimates must be continually revised as a result of new information obtained from drilling and production history, new geological and geophysical data and changes in economic conditions.

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Proved reserves are estimated quantities of gas, crude oil, and condensate which geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Quantity of Oil and Gas Reserves	Oil (Bbls)	Gas (Mcf)
Total proved reserves at December 31, 1999	256,224	22,217,942
Revisions to previous estimates	(10,175)	(18,507,271)
New discoveries and extensions	3,793	1,868,000
Production	(64,707)	(911,671)
Total proved reserves at December 31, 2000	185,135	4,667,000
Revisions to previous estimates	(13,476)	(841,816)
Production	(40,769)	(815,184)
Total proved reserves at December 31, 2001	130,890	3,010,000
Proved developed reserves:		
December 31, 2001	128,783	2,613,000
December 31, 2000	182,106	3,134,000

Capitalized Costs of Oil and Gas Producing Activities

The following table sets forth the aggregate amounts of capitalized costs relating to the Company's oil and gas producing activities and the aggregate amount of related accumulated depletion, depreciation and amortization as of December 31, 2001:

Unproved properties and prospect generation costs not being amortized	$ 221,832
Proved properties being amortized	27,348,510
Less accumulated depletion, depreciation, amortization and impairment	(24,406,674)
Net capitalized costs	$ 3,163,668

During 2001, the Company recorded an impairment charge on its oil and gas properties of $1.1 million. The impairment reflects the recognition of additional Buccaneer Field plugging and abandonment costs.

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During 2000, the Company recorded an impairment charge on its oil and gas properties of $10,754,976. The impairment was comprised of a non-cash write-off of proved reserves from the Buccaneer Field of $5.4 million and the recognition of associated plugging and abandonment costs estimated to be $5.4 million.

Costs Incurred in Oil and Gas Producing Activities

The following table reflects the costs incurred in oil and gas property acquisition, exploration and development activities during the periods indicated:

	Year Ended December 31,	
	2001	2000
Property acquisition costs	$ --	--
Exploration costs	143,829	467,256
Development costs	773,115	1,417,790
	$ 916,944	1,885,046

Standardized Measure of Discounted

Future Net Cash Flows

The following table reflects the Standardized Measure of Discounted Future Net Cash Flows relating to the Company's interest in proved oil and gas reserves as of:

	December 31, 2001	December 31, 2000
Future cash inflows	$ 10,374,365	51,320,776
Future development costs	(1,190,585)	(2,397,403)
Future production costs	(1,761,074)	(2,477,723)
Future net cash inflows before income taxes	7,422,706	46,445,650
Future income taxes	10,473,236	(3,490,661)
Future net cash flows	17,895,942	42,954,661
10% discount factor	(920,497)	(6,307,411)
Standardized measure of discounted future net cash inflow	$ 16,975,445	36,647,578

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Future net cash flows at each year end, as reported in the above schedule, were determined by summing the estimated annual net cash flows computed by: (1) multiplying estimated quantities of proved reserves to be produced during each year by current prices and (2) deducting estimated expenditures to be incurred during each year to develop and produce the proved reserves (based on current costs).

Income taxes were computed by applying year-end statutory rates to pretax net cash flows, reduced by the tax basis of the properties and available net operating loss carryforwards. The annual future net cash flows were discounted, using a prescribed 10% rate, and summed to determine the standardized measure of discounted future net cash flow.

The Company cautions readers that the standardized measure information which places a value on proved reserves is not indicative of either fair market value or present value of future cash flows. Other logical assumptions could have been used for this computation which would likely have resulted in significantly different amounts. Such information is disclosed solely in accordance with Statement 69 and the requirements promulgated by the SEC to provide readers with a common base for use in preparing their own estimates of future cash flows and for comparing reserves among companies. Management of the Company does not rely on these computations when making investment and operating decisions. Principal changes in the Standardized Measure of Discounted Future Net Cash Flows attributable to the Company's proved oil and gas reserves for the periods indicated are as follows:

	December 31, 2001	December 31, 2000
Sales and transfers, net of production costs*	$ (3,538,653)	(4,150,204)
Acquisition of reserves	--	--
Net change in estimated future development costs	980,063	(5,495,874)
Extensions and discoveries	--	14,431,684
Revisions in previous quantity estimates	(1,663,095)	2,280,195
Net changes in sales and transfer prices, net of production costs	27,307,388)	6,125,097
Accretion of discount	3,688,897	1,499,151
Net change in income taxes	13,719,714	(153,634)
Change in production rates (timing) and other	(5,551,671)	7,207,408
Net change	$(19,672,133)	21,743,823

*47% of the Company's estimated proved oil reserves and 39% of its estimated proved gas reserves were being produced at December 31, 2001.

(13) Sales of Assets

On January 22, 2001, the Company sold its 50% interest in the Black Marlin Pipeline System to affiliates of the Williams Companies, Inc. for approximately $4.6 million. The Black Marlin Pipeline System includes a 75-mile gas and condensate gathering line with related shore facilities servicing the High Island Area, offshore Texas (the "Black Marlin Pipeline") and a 3-mile lateral pipeline extending from High Island Block A-5 to an interconnection to the Black Marlin Pipeline in High Island Block A-6 (the "A-5 Lateral").

This disposition was consummated, in part, through a sale of all of the outstanding capital stock of Black Marlin Pipeline Company (formerly an indirect wholly owned subsidiary of the Company) the owner of a 50% interest in the Black Marlin Pipeline, pursuant to a Purchase and Sale Agreement dated January 12, 2001 (the "Stock Purchase Agreement") among Black Marlin Energy Company, a wholly owned subsidiary of the Company, MCNIC Pipeline & Processing Company ("MCNIC"), WBI Southern, Inc. ("WBI") and Williams Field Services Group, Inc. The Company received $3.6 million for the outstanding capital stock of Black Marlin Pipeline Company for a gain of $1,305,534.

The remaining part of this disposition was consummated through the sale of the A-5 Lateral owned 50% by Blue Dolphin Pipe Line Company, a wholly owned subsidiary of the Company ("BDPL"), pursuant to a Purchase and Sale Agreement dated January 12, 2001, among BDPL, MCNIC, WBI and Williams Field Services - Gulf Coast Company, L.P. The Company received $1.0 million for its interest in the A-5 Lateral, for a gain of $112,092.

In connection with Blue Dolphin Exploration's acquisition of American Resources in December 1999, Blue Dolphin Exploration arranged for Fidelity Oil to acquire an 80% interest in American Resources oil and gas assets located in the Gulf of Mexico for approximately $24.2 million. For the right to participate in the acquisition of these assets, Fidelity Oil agreed to assign Blue Dolphin Exploration 10% of its working interest in the proved properties acquired from American Resources after it has recovered its investment in these properties. In the fourth quarter 2001, Fidelity Oil had recovered its investment in the proved properties. However, instead of assigning 10% of its interest in the proved properties, Fidelity Oil paid Blue Dolphin $1.4 million in cash in December 2001. The proceeds were accounted for as a reduction to capitalized costs of oil and gas properties.

(14) Subsequent Event

In February 2002, the Company acquired a 1/3 interest in the Blue Dolphin Pipeline System and the inactive Omega Pipeline from MCNIC. Pursuant to the terms of the purchase and sales agreement, Blue Dolphin issued MCNIC a $750,000 promissory note due December 31, 2006, with required monthly payments to be made out of 90% of the net revenues of the interest acquired. The note bears interest at the rate of 6% per annum and is secured by the interest acquired. Additionally, a contingent payment of up to $750,000 will be made, if the promissory note is retired before its maturity date, payable annually after the

promissory note is retired until December 31, 2006 out of 50% of the net revenues from the interest acquired. The termination date, December 31, 2006, will be extended by one additional year, up to a maximum of two years, for years in which non-recurring, extraordinary expenditures attributable to the interest acquired exceeds $200,000, in the aggregate, during any year.

On December 2, 1999, the Company, through Blue Dolphin Exploration, acquired a 75% ownership interest in American Resources by purchasing approximately 39.5 million shares of American Resources common stock. On February 19, 2002, the Company completed its acquisition of American Resources, pursuant to the Amended and Restated Agreement and Plan of Merger dated as of December 19, 2001 (the "Merger Agreement"). Pursuant to the Merger Agreement, American Resources became a wholly owned subsidiary of the Company and each outstanding share of (i) American Resources common stock, par value $.00001 per share, was converted into the right to receive, at the option of the holder, either $.06 per share in cash or .0362 of a share of the Company's Common Stock, par value $.01 per share (the "Common Stock"), and (ii) American Resources Series 1993 Preferred Stock, par value $12.00 per share, was converted into the right to receive, at the option of the holder, either $.07 in cash or .0301 of a share of Common Stock.

As a result of elections made by American Resources' stockholders, the Company will issue approximately 273,336 shares of Common Stock and will pay approximately $255,000 in cash.

Item 8. Changes in and Disagreements with Accountants on Accounting and Financial Disclosures

Upon the recommendation of the Registrant's Audit Committee, on February 15, 2002, the Registrant's Board of Directors decided not to renew the engagement of KPMG LLP ("KPMG") as the Registrant's principal accountant and selected Mann Frankfort Stein & Lipp CPAs, LLP ("Mann Frankfort") as KPMG's replacement.

In connection with the audits of the Registrant's two fiscal years ended December 31, 2000, and the subsequent interim period through February 15, 2002, there were no disagreements with KPMG on any matter of accounting principles or practices, financial statement disclosure, or auditing scope or procedures, which disagreements if not resolved to their satisfaction would have caused them to make reference in connection with their opinion to the subject matter of the disagreement. The audit reports of KPMG on the consolidated financial statements of the Registrant and subsidiaries as of and for the years ended December 31, 2000 and 1999 did not contain any adverse opinion or disclaimer of opinion, nor were they qualified or modified as to uncertainty, audit scope, or accounting principles, except that KPMG's report on the Registrant's consolidated financial statements for the years ended December 31, 2000 and 1999 contained a separate paragraph stating that "As discussed in Note 1 to the consolidated financial statements, effective January 1, 1999, the Company changed its method of accounting for costs of start-up activities."

During the two fiscal years ended December 31, 2000 and the subsequent interim period prior to engaging Mann Frankfort, neither the Registrant nor anyone on its behalf consulted with Mann Frankfort regarding the application of accounting principles to a specified transaction, either completed or proposed; or the type of audit opinion that might be rendered on the Registrant's financial statements, and neither a written report nor oral advice was provided to the Registrant by Mann Frankfort that was an important factor considered by the Registrant in reaching a decision as to any accounting, auditing or financial reporting issue.

PART III

Item 13. Exhibits and Reports on Form 8-K

(a) 1. Exhibits

No. Description

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	3.1	(1)	Certificate of Incorporation of the Company.
	3.2	(2)	Certificate of Correction to the Certificate of Incorporation of the Company dated June 30, 1987.
	3.3	(2)	Certificate of Amendment to the Certificate of Incorporation of the Company dated June 30, 1987.
	3.4	(2)	Certificate of Amendment to the Certificate of Incorporation of the Company dated December 11, 1989.

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	3.5	(2)	Certificate of Amendment to the Certificate of Incorporation of the Company dated December 14, 1989.
	3.6	(2)	Bylaws of the Company.
	3.7	(4)	Certificate of Amendment to the Certificate of Incorporation of the Company dated December 8, 1997.
	4.1	(2)	Specimen Certificate of Blue Dolphin Energy Company Common Stock.
*	10.1	(3)	Blue Dolphin Energy Company 1996 Employee Stock Option Plan.
*	10.2	(7)	Blue Dolphin Energy Company 2000 Stock Incentive Plan
	10.12	(5)	Asset Purchase Agreement between WBI Southern, Inc., Blue Dolphin Pipeline Company, Buccaneer Pipe Line Co. and Mission Energy, Inc.
	10.13	(5)	Purchase and Sale Agreement between Enron Pipeline Company, Black Marlin Energy Company and Blue Dolphin Energy Company.
	10.14	(5)	Asset Purchase Agreement between WBI Southern, Inc., BlackMarlin Pipeline Company and Black Marlin Energy Company.
	10.15	(5)	Asset Purchase Agreement between MCNIC Offshore Pipeline & Processing Company, Black Marlin Pipeline Company and Black Marlin Energy Company.
	10.16	(6)	Investment Agreement, as amended, by and between American Resources Offshore, Inc. and Blue Dolphin Exploration Company.
	10.18	(8)	Purchase and Sale Agreement by and between Williams Field Services Group, Inc. and Black Marlin Energy Company
	10.19	(8)	Purchase and Sale Agreement by and between Williams Field Services - Gulf Coast Company, L.P. and Blue Dolphin Pipeline Company

10.20	(9)	Amended and Restated Agreement and Plan of Merger dated as of December 19, 2001 (the "Merger Agreement") among Blue Dolphin Energy Company, American Resources Offshore, Inc. and BDCO Merger Sub, Inc.
10.21	(10)	Amended and Restated Agreement and Plan of Merger, as amended, among American Resources Offshore, Inc., Blue Dolphin Energy Company and BDCO Merger Sub, Inc. and American Resources Offshore, Inc.
10.22	(9)	Letter agreement between Blue Dolphin Exploration Company and Fidelity Exploration & Production Company.
10.23	(9)	Amendment No.1 to the Amended and Restated Agreement and Plan of Merger.

16.1	(10)	Letter from KPMG, L.L.P.
21.1**		List of Subsidiaries of the Company.
23.1**		Consent of Ryde r Scott Company, independent petroleum engineers.

(1) Incorporated herein by reference to Exhibits filed in connection with Registration Statement on Form S-4 of ZIM Energy Corp. filed under the Securities Act of 1933 (Commission File No. 33-5559).

(2) Incorporated herein by reference to Exhibits filed in connection with Form 10-K of Blue Dolphin Energy Company for the year ended December 31, 1989 under the Securities and Exchange Act of 1934, dated March 30, 1990 (Commission File No. 000-15905).

(3) Incorporated herein by reference to Exhibits filed in connection with Form 10-K of Blue Dolphin Energy Company for the year ended December 31, 1995 under the Securities and Exchange Act of 1934, dated March 29, 1996 (Commission File No. 000-15905).

(4) Incorporated herein by reference to Exhibits filed in connection with the definitive Information Statement on Schedule 14C of Blue Dolphin Energy Company under the Securities and Exchange Act of 1934, dated November 18, 1997 (Commission File No. 000-15905).

(5) Incorporated herein by reference to Exhibits filed in connection with Form 8-K of Blue Dolphin Energy Company under the Securities and Exchange Act of 1934, dated March 1, 1999 (Commission File No. 000-15905).

(6) Incorporated herein by reference to Exhibits filed in connection with Schedule 13D of Blue Dolphin Energy Company under the Securities and Exchange Act of 1934, dated October 22, 1999 (Commission File No. 000-15905).

(7) Incorporated herein by reference to Exhibits filed in connection with

the Proxy Statement of Blue Dolphin Energy Company under the Securities and Exchange Act of 1934, dated May 18, 2000 (Commission File No. 000-15905).

(8) Incorporated herein by reference to Exhibits filed in connection with Form 8-K of Blue Dolphin Energy Company under the Securities and Exchange Act of 1934, dated January 22, 2001 (Commission File No. 000-15905).

(9) Incorporated herein by reference to Exhibits filed in connection with Form S-4 of Blue Dolphin Energy Company under the Securities Act of 1933 (Commission File No. 333-82186).

(10) Incorporated herein by reference to Exhibits filed in connection with Form 8-K of Blue Dolphin Energy Company under the Securities and Exchange Act of 1934, dated February 25, 2002 (Commission File No. 000-15905).

* Management Compensation Plan.
** Filed herewith.

(b) Reports on Form 8-K

On December 20, 2001, the Company filed a current report on Form 8-K dated December 20, 2001, reporting an Amended and Restated Agreement and Plan of Merger with American Resources Offshore, Inc. The items reported in such current report were Item 5 (Other Events).

On February 25, 2002, the Company filed a current report on Form 8-K dated February 15, 2002, reporting a change in Certifying Accountant. The items reported in such current report were Item 4 (Change in Registrant's Certifying Accountant).

On March 1, 2002, the Company filed a current report on Form 8-K dated February 19, 2002, reporting it completed the acquisition of American Resources Offshore, Inc. The items in such current report were Item 2 (Acquisition or Disposition of Assets).

On March 13, 2002, the Company filed a current report on Form 8-K dated February 28, 2002, reporting the acquisition of an additional 1/3 interest in the Blue Dolphin Pipeline System from MCNIC Pipeline & Processing Company. The items reported in such current report were Item 5 (Other Events).

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

BLUE DOLPHIN ENERGY COMPANY
(Registrant)

By: /s/ Michael J. Jacobson

Michael J. Jacobson, President
(principal executive officer)

Date: March 28, 2002

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Michael J. Jacobson Michael J. Jacobson	President (principal executive officer)	March 28, 2002
/s/ G. Brian Lloyd G. Brian Lloyd	Vice President, Treasurer (principal accounting and financial officer)	March 28, 2002
/s/ Ivar Siem Ivar Siem	Chairman	March 28, 2002
/s/ Harris A. Kaffie Harris A. Kaffie	Director	March 28, 2002
/s/ Michael S. Chadwick Michael S. Chadwick	Director	March 28, 2002
/s/ Robert D. Wagner, Jr. Robert D. Wagner, Jr.	Director	March 28, 2002